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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for a Certificate of Public Convenience and Necessity for the Alberhill System Project.	Application No. 09-09-022

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) SECOND AMENDED MOTION TO CORRECT CLERICAL ERROR IN AMENDED MOTION TO SUPPLEMENT THE RECORD

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Dated: **June 22, 2021**

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Southern California Edison Company ("SCE") has prepared this Second Amended Motion ("Second Amended Motion") to correct a clerical error in SCE's *Amended Motion to Supplement the Record* (the "Amended Motion") with regard to spreadsheet tabular data attached to SCE's Amended Motion in the Alberhill System Project proceeding ("Alberhill Project").[1] SCE filed its original Motion to Supplement the Record on May 11, 2020 and subsequently filed its Amended Motion on February 1, 2021 to identify corrections in its analysis. Subsequent thereto, SCE identified clerical errors in certain data tables attached to SCE's analysis.

Specifically, when preparing the spreadsheets and corresponding results tables, some of the formulas were transferred incorrectly, resulting in minor rounding errors and truncation of some of the data. In some cases, discrepancies were introduced by rounding and/or truncating of interim results and in other cases there were mismatches in the rows or columns transferred. The

[1] SCE initially filed this document as an Errata; however, on June 29, 2012, the CPUC docket office informed SCE that the term "Errata" is no longer recognized and that the document was required to be refiled as an "Amendment". Accordingly, SCE is now refiling this document as a "Second Amended Motion".

revisions do not change the discussion, or any conclusions contained in the documents, but rather are provided solely for transparency and clarity. Because similar source data appear in differing context throughout SCE's analysis, various tables in the following documents were affected:

- **Exhibit C-2 (Second Amended)** - Revised Planning Study [clean version attached as Exhibit C-2 (Second Amended)];
- **Exhibit C-2 (Second Amended) Redline –** Revised Planning Study [redlined version attached as Exhibit C-2 (Second Amended) Redline];
- **Exhibit F-1 (Second Amended)** – Forecasted Impact of ASP on service reliability performance [clean version attached as Exhibit F-1 (Second Amended)];
- **Exhibit F-1 (Second Amended) Redline** – Forecasted Impact of ASP on service reliability performance [redlined version attached as Exhibit F-1 (Second Amended) Redline];
- **Exhibit G-2 (Second Amended)** – Cost/Benefit Analysis of additional alternatives to ASP [clean version attached as Exhibit G-2 (Second Amended)]; and
- **Exhibit G-2 (Second Amended) Redline –** Cost/Benefit Analysis of additional alternatives to ASP [redlined version attached as Exhibit G – (Second Amended) Redline].

To reflect these revisions, please see Exhibits attached hereto, which include clean and redline versions of each revised document. Except as provided in this Second Amended Motion, SCE believes that the Amended Motion, including all attachments, is accurate in all other respects.

Respectfully submitted,

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EXHIBIT C-2 (SECOND AMENDED)

Alberhill System Project

Data Request Item C – Planning Study ED-

Alberhill-SCE-JWS-4: Item C

Revision 2.1 (Second Amended Motion)

June 16, 2021

Revision Summary

Revision 2.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This second amended motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 2

Revision Date: January 29, 2021

Summary of Revisions:

This revision corrects errors identified by Southern California Edison (SCE) in the cost-benefit analysis results reported in Section 8 of this Planning Study. Specifically:

1. SCE identified errors in calculated probabilities of coincidental line outages and specific system loading conditions that would result in unserved customer load. As a result, the initial analysis substantially overstated the monetization of the Flex-1 alternative performance metric. The Flex-1 metric addresses load at risk of being unserved when N-2[1] line outages occur. The previous version of the analysis also considered N-1-1[2] outages. These N-1-1 outages are no longer considered in order to simplify the analysis and due to their very low impact on results when applying the updated probabilities.
2. SCE identified errors in the application of the SCE Value of Service (VoS) Study in assigning a monetary value to unserved customer load.
    a. The original analysis incorrectly weighted the monetization value based on the number of customers in each customer class as a fraction of the total customer count. This contrasts with the correct approach of valuing unserved energy based on the amount of electrical demand in each customer class as a fraction to the total amount of electrical demand served. As a result, the monetized value of the metrics was substantially increased in the current revision and is more representative of the cost impact of outages.
    b. The original analysis did not reflect SCE's practice to minimize the impact of an extended outage to any single set of customers (e.g., a distribution circuit or distribution substation), where practical, by periodically rolling the outages throughout the system. As a result, a one-hour outage monetization rate in the

[1] N-2 outages are associated with a single event causing two system elements (in this case lines) to be out of service at the same time.

[2] N-1-1 outages are associated with one system element being out of service (a planned or unplanned outage) followed by an unplanned outage for a second element.

VoS Study is now applied for each hour of the period during which load would be unserved, rather than assuming the entire duration of an outage would be experienced by a smaller group of customers, as was the case in the original analysis. This is the case for all metrics other than the Flex 2-1 metric where system operators would not have the flexibility to roll outages among customers due to the large amount of load at risk of being unserved in this metric. In this case, a lesser value, the average of one-hour and 24-hour outage monetization rates, is applied.

c. SCE identified an error that overstated the monetization rate for commercial and industrial (C&I) customers when the small/medium business (SMB) customers were combined with C&I customers as a single customer class. The costs of outages for residential, C&I, and SMB customer classes are now calculated individually at their correct individual outage cost rates.

The net effect of correcting the errors in application of the VoS Study is an increase in the monetized value of each MWh of projected interruption of service to customers, partially offsetting the probability weighting error identified above.

3. The Flex 2-1 and Flex 2-2 metrics were modified to no longer constrain the event that drives the impact of these metrics to occur at peak summer load conditions. This is consistent with the approach for other metrics, in that the probability weighting in the monetization reflects the random timing of occurrence of such an event with loading conditions varying throughout the year. This change reduces the monetized value of these benefits; but this reduction is offset in part by the change in the application of the VoS study described above. Additionally, the Flex 2-2 metric was modified to reflect a more realistic scenario in which only a single transformer would be left to serve the Valley South System load.

Other less significant changes to the Planning Study and supporting analysis were also made to clarify, simplify, or correct some areas of the analysis and/or its description. These areas were identified as a result of additional independent SCE internal reviews performed after identifying the errors described above and are summarized below:

1. For clarity, the non-monetized Expected Energy Not Served (EENS) metrics (EENS (N-0) and EENS (N-1)) metrics used in the original Planning Study and supporting analysis are now named Load at Risk (LAR). The term EENS might imply that the metric is probability weighted but probabilities are not assigned in the analysis until the metrics are monetized. Monetized values are still designated as EENS because probabilities have been assigned.
2. Project scope and associated costs have been added to several alternatives to correct N-1 line capacity violations that occur within the first ten years of the project planning horizon. These line violations are projected to occur as a result of increased load growth in the system in the event no project is implemented. For some alternatives, the need to correct the line violations is accelerated by changes in the system design of the respective alternative and in other cases the need is delayed or eliminated. These line violations were previously identified and discussed extensively in this Planning Study; however,

rather than including the associated scope and cost (to mitigate these violations) in the cost-benefit analysis, the impact of the line violations was previously reflected as reduced system benefits for the affected alternatives. The affected alternatives include all alternatives that transfer substations in the northern part of the Valley South System (Mira Loma, Menifee and all the alternatives that transfer load from Valley South to Valley North). The overall impact of this change to the cost-benefit analysis is minor because the cost of addressing the line violation is not large relative to the overall project scope, and the cost is partially offset by an increase in benefits due to correcting the line violations.

3. The market participation revenues for alternatives that include Battery Energy Storage Systems (BESS) were modified to include Resource Adequacy[3] payments for the eight months of the year where the BESS would not be dedicated to the system reliability need. This primarily affects the Centralized BESS alternative because the value is not significant for other alternatives due to the smaller quantity of batteries and the discounting associated with their later addition. The change does not significantly affect the cost-benefit analysis performance of the Centralized BESS alternative relative to other alternatives.
4. The timing of Operations and Maintenance costs for all alternatives is now correctly applied beginning at the project in-service date, as opposed to the project need date, at which it was previously applied. This change results in a minor decrease in the cost (Present Value Revenue Requirement or PVRR) for each alternative and does not significantly affect the relative cost-benefit analysis performance of alternatives.
5. The assumed start of construction for ASP was delayed by 18 months in this revision of the analysis to be consistent with all other alternatives. Previously the construction start date was in 2021, which is not realistic. The earlier start date negatively impacted the ASP relative to other alternatives; because, while its costs were incurred earlier, its benefits were not accelerated relative to other alternatives. Now all alternatives have a common set of assumptions – consistently accruing benefits at the project need date (2022)[4] and entering construction in 2023. The earlier construction spend for ASP in the previous version of the analysis increased ASP costs relative to other alternatives because the costs of other alternatives were discounted more heavily in the PVRR calculation due to their later construction start dates. The assumption on start of benefits has not changed in this version of the planning study. The overall goal of the analysis continues to be the consistent treatment of alternatives with respect to timing of costs and benefits so that the analysis reflects the true system performance of alternatives without being influenced by the large swings in results that could occur based on subjective judgments of the likely relative timing at which cost and benefits might actually accrue.

[3] Resource adequacy payments reflect the market value of capacity added to the system by the BESS additions. In accordance with current market participation rules, this capacity value is credited only in months when the capacity is not likely required to satisfy a system reliability need due to a shortage in transformation capacity.

[4] Benefits are started on the need date rather than in-service date for all alternatives to maintain consistency among the alternatives, to simplify the analysis and to ensure that the near-term load forecast has a more dominant impact on the relative performance of the alternatives.

6. For clarity, SAIDI (System Average Interruption Index), SAIFI (System Average Interruption Frequency Index), and CAIDI (Customer Average Interruption Duration Index) metrics have been removed from the analysis. These metrics were calculated directly from LAR values, so they do not provide unique insight on the relative performance of system alternatives. Additionally, they were calculated based on a different base customer value than SAIDI, SAIFI, and CAIDI values reported by SCE in other supplemental analysis submittals[5] by SCE and would cause confusion if these data are compared among these submittals.
7. Other minor editorial corrections and clarifications.

Revision 1

Revision Date: May 6, 2020

Summary of Revisions:

Minor change to address an error in a data point in Figure 5-1.

[5] See A.09-09-022 CPUC-JWS-2 Q.01e and A.09-09-022 CPUC-JWS-2 Q.01d.

1.0 Executive Summary

Abstract

In Decision (D.) 18-08-026 for the Alberhill System Project (ASP) proceeding, the California Public Utilities Commission (CPUC) took no action on the ASP and directed Southern California Edison (SCE) to supplement the existing record with specific additional analyses. These additional analyses include, in part, this planning study that supports the project need and includes applicable planning criteria and reliability standards.

In considering both the need for a project and comparing a wide range of project alternatives, this planning study:

- provides historical context on the evaluation of the Valley South System;
- compares its configuration to other SCE subtransmission systems;
- summarizes the basis for forecasted load;
- addresses compliance with project objectives, system planning criteria, and reliability standards;
- applies forward-looking system performance metrics to assess effectiveness of alternatives in meeting project objectives;
- documents an objective cost/benefit analysis based on impact to customers; and
- considers a range of monetized and non-monetized risks.

This planning study confirms the need for a project and more specifically reinforces selecting a comprehensive solution for the Valley South System that addresses the transformer capacity shortfall, forecast for 2022, and provides adequate system tie-lines to another system in order to improve reliability and resiliency. Further, the planning study supports the ASP as SCE's recommended solution to address the defined objectives for the project.

System Background and Needs

The San Jacinto region houses the Valley System, made up of the Valley North and Valley South Systems combined, and serves approximately 325,000 metered customers and provides electricity to approximately 1,000,000 people. The Valley South System, which is the focus of this Planning Study, serves approximately 560,000 people, including nearly 6,000 critical care customers, over approximately 380 square miles in southwestern Riverside County. The Valley South System is served by the Valley Substation, which is unique within SCE's electric system in that it is the only substation that interfaces with the California Independent System Operator (CAISO)-controlled bulk electric system at 500/115 kilovolts (kV) and then directly serves 115/12 kV distribution substation load. The Valley Substation has been constructed to its ultimate system design capacity (2,240 megavolt-amperes or MVA with 1,120 MVA serving each of the Valley North and Valley South Systems respectively) and the Valley South System has demonstrated peak loading values that result in a 99.9% utilization[6] during peak loading conditions. Thus, even very modest continued load growth will negatively impact the ability of SCE to adequately serve the Valley South System. Further, the Valley South System is the only subtransmission system within SCE's entire territory (among its 56 separate subtransmission systems) that operates with zero tie-lines to other systems. The lack of system tie-lines results in an isolated system which negatively impacts the reliability and resiliency of the system due to the inability to transfer load during typically planned-for system contingency events and unplanned outages, including high-impact, low-probability events[7]. The combination of a very high utilization percentage and no system tie-lines requires operators to implement a pre-emptive temporary mitigation measure[8] by placing in service an installed spare transformer at Valley Substation during periods of high demand. This is the only system in SCE's territory that requires this action. The use of this spare transformer has negative implications for reliability and resiliency for both Valley South and Valley North Systems because it cannot be relied on for its intended function as a spare when used to serve load.

Project Objectives

The purpose of this Planning Study is to: establish the basis for a project in the Valley South System under applicable planning criteria and reliability standards; evaluate a broad range of alternatives to satisfy the electrical need; and recommend the best solution. SCE's project objectives (which were described in the project Proponent's Environmental Assessment) include:

- Serve current and long-term projected electrical demand requirements in the Electrical Needs Area.
- Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer substations from the current Valley South System.
- Transfer (or otherwise relieve[9]) a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through the 10-year planning horizon.
- Provide safe and reliable electrical service consistent with SCE's Subtransmission Planning Criteria and Guidelines.
- Increase electrical system reliability by constructing a project in a location suitable to serve the Electrical Needs Area (i.e., the area served by the existing Valley South System).
- Meet project need while minimizing environmental impacts.
- Meet project need in a cost-effective manner.

This Planning Study is intended to address the need and required timing for such a project, consider additional alternatives that can meet these project objectives, and help support a determination of

[6] The 2018 adjusted peak demand, which includes weather adjustments to reflect a 1-in-5 year heat storm, was 99.9% of the Valley South System ultimate system design capacity (1,120 MVA). 2019 adjusted peak loads were slightly lower than 2018. 2020 adjusted peak loads have not yet been finalized but are expected to be similar to, or higher than, both 2018 and 2019 values based on the unadjusted values during the September 2020 heat storm.

[7] See Section 3.0 System Configuration for additional information related to Valley South's lack of system tie-line.

[8] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item H.

[9] Clarified from original objectives so as not to preclude non-wires alternatives.

which of the alternatives (including the ASP) best satisfies the project needs from the overall perspective of system benefit, cost and risk.

The approach used in this study is as follows:

- Provide supporting evidence confirming system needs.
- Establish a project need date based on SCE's load forecast and validation of that need with two independent load forecasts.
- Develop a set of robust alternatives that meet or exceed the 10-year load forecast.
- Assess compliance with SCE's Subtransmission Planning Criteria and Guidelines.
- Assess each alternative using forward-looking quantitative metrics to assess the effectiveness of each alternative in meeting the project capacity, reliability, and resiliency[10] needs that currently exist in the area served by the Valley South System in its current configuration.
- Site and route the alternatives in order to evaluate feasibility and assess the relative environmental impacts of the alternatives.
- Estimate the costs of these alternatives and conduct a cost-benefit analysis that considers the benefits and costs over a 30-year life of the installed facilities.
- Identify risks which could impact the ability of the alternatives to meet project needs or alter their cost effectiveness.
- Recommend a preferred solution based on a comprehensive evaluation of alternatives.

Load Forecast

A 10-year load forecast (2019-2028)[11] prepared by SCE showed that the load on the Valley South System is expected to exceed the existing transformer capacity at Valley Substation by 2022[12] and that system load would continue to increase at a modest rate (<1% per year) over the next decade. The development of this forecast is consistent with CPUC direction that SCE use the California Energy Commission (CEC) annual California Energy Demand (CED) forecast produced as part of the annual Integrated Energy Policy Report (IEPR). Additionally, it is consistent with observed trends of historical loading data and historical population growth for the Valley South System service area. Two independent load forecasts for the Valley South System conducted by Quanta Technology[13], using distinct methodologies, confirm this need date and yield similar results: loading of the Valley South System is projected to exceed existing capacity in 2022 and modest positive growth rates would be expected to continue. The SCE forecast, as well as the independent

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[10] Reliability refers to a utility's ability to meet service requirements under normal (N-0) and N-1 contingency conditions. Resiliency refers to a utility's ability to keep its systems functioning and serving customers under extraordinary circumstances. These terms relate directly to the system tie-line project objective. See Appendix A for a complete discussion of these terms.

[11] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.

[12] Slightly lower 2019 adjusted peak load data slightly shift the need date to 2023. This modest shift does not impact the results of the analysis presented herein. The impact of higher actual peak loads experienced in 2020 have not yet been determined, but SCE considers it is more likely to maintain or advance the need date rather than delay it.

[13] Quanta Technology is an expertise-based, independent technical, consulting, and advisory services company specializing in the electric power and energy industries.

forecasts, incorporated accepted methods for consideration of Distributed Energy Resources (DERs) including energy efficiency, demand response, and behind-the-meter generation (See Section 5.0).

Development and Analysis of Alternatives

SCE and Quanta Technology developed a robust list of project alternatives based on a variety of inputs including: the direction of the CPUC in the ASP decision; the previous assessment of alternatives in the ASP EIR; and public and stakeholder engagement. Project alternatives include:

- Minimal Investment Alternatives (e.g., utilize existing equipment or make modest capital investments of <$25M);
- Conventional Alternatives (e.g., substation and wires-based solutions with system tie-lines);
- Non-Wires Alternatives (NWA) (e.g., battery energy storage systems (BESS), as well as the consideration of demand side management (DSM) and other DERs[14]); and
- A combination of Conventional Alternatives and Non-Wires Alternatives (herein referred to as Hybrid Alternatives).

These alternatives are described in Section 6.1 of this Planning Study.

SCE screened project alternatives against the project objectives. Those alternatives that met all of the project objectives were carried forward for evaluation using a combination of forward-looking quantitative reliability/resiliency metrics and other qualitative assessments. Although NWAs on their own do not meet all the project objectives (specifically the creation of system tie-lines), SCE carried forward a BESS-only alternative in the analysis in order to investigate the relative cost-benefit performance of a BESS solution alone and when paired with Conventional Alternatives to demonstrate the benefit of the system tie-lines. Importantly, establishing system tie-lines satisfies both the capacity and the reliability/resiliency needs facing the Valley South System by providing the ability to transfer electrical load during system contingency events.[15]

In order to assess and compare the project alternatives on a technical basis, the system was modelled and analyzed using the General Electric Positive Sequence Load Flow (PSLF) analysis software. PSLF is a software tool commonly used by power system engineers throughout the utility power systems industry, including many California utilities and the California Independent System

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[14] Ultimately in order to consistently address DER performance and cost across alternatives, battery energy storage systems were modelled as surrogates for all DER types, either on a centralized basis (subtransmission level) or on a distributed basis (distribution level, front of meter resources).

[15] Hybrid alternatives that adopt NWAs first, for capacity relief and to defer investment in Conventional Alternatives, were considered in project screening but not carried forward for further study. This is because system tie-line creation was deemed to be a priority at the onset of the project and system load transfers associated with system tie-line creation created sufficient capacity relief for more than 10 years. Accordingly, addition of NWAs at the project onset would be duplicative and inefficient from a cost perspective. Hybrid alternatives that were carried forward adopt NWAs later in time to address capacity needs beyond those initially satisfied by the system configuration changes associated with tie-line creation.

Operator (CAISO), to simulate electrical power transmission networks and evaluate system performance. To support this analysis, one of the two Quanta Technology load forecasts, the Spatial Load Forecast (SLF), was extended to 30 years, roughly corresponding to the economic life of conventional transmission and distribution assets that make-up the ASP and all of the alternatives that meet the project objectives. This extended SLF looks at small, discrete areas (150 acres in size) and considers geo-referenced individual customer meter data (peak load), local land-use information, and county and city master and specific development plans and thus is particularly well-suited among load forecasting methods for long term forecasts.

The reliability/resiliency metrics were quantified using the power system models of the Valley electrical systems in their current configurations and as they would be configured with the various alternatives. An 8,760 hour load shape[16] of both the Valley North and Valley South Systems was utilized and scaled according to the peak demand given by the SLF for each of the years under study. During each hour, the model determines how much, if any, load is required to be transferred to an adjacent system (if system tie-line capacity is available) or dropped (if system tie-line capacity is not available) to maintain the system within specified operating limits consistent with SCE subtransmission planning criteria. The dropped (or unserved) load is then summed over the 8,760 hours of the year, for base (N-0) and contingency (N-1, N-2)[17] conditions, to provide the basis for most of the metrics described below. The reliability/resiliency metrics used to evaluate the alternatives (discussed in greater detail in Section 6.3) include:

- Load at Risk (LAR) – total load required to be curtailed during periods of time in which subtransmission operating criteria were not met (thermal overload/voltage violation) multiplied by the number of hours of violation, quantified in megawatt-hours (MWh). This metric is calculated for operating conditions with all facilities in service (N-0 conditions) and with a single facility out of service (N-1 contingency conditions).
- Maximum Interrupted Power (IP) – maximum power, in MW, curtailed during thermal overload and voltage violation periods.

- Losses – total losses in the system, quantified in MWh, for each alternative (this is the only metric not driven by unserved load and is reflective of the electrical efficiency of each alternative).
- Flexibility 1 (Flex-1) – accumulation of LAR for all possible N-2 contingencies. N-2 contingencies are only considered for lines that share common structures. System tie-lines are utilized when needed and available. Thus, the Flex-1 metric provides a relative indication of the effectiveness of system tie-lines and the locational benefit of any new power source substations in improving system reliability and resiliency in the context of line outages.

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[16] There are approximately 8,760 hours in a year. A common tool used for planning purposes is to construct a time-series data set of the system load on an hourly basis.

[17] N-0, N-1, and N-2 are electric system planning designations for operating contingencies, where N-0 refers to normal operation with all major system elements (e.g., transformers, lines, and busses) in service and N-1 and N-2 refer to scenarios with 1 or 2 elements out of service, respectively.

- Flexibility 2-1 (Flex-2-1) – amount of LAR in the Valley South System under a complete loss of transformation capacity in the Valley Substation) due to a high impact, low probability (HILP) event. This event is postulated to be similar to substation fires that have occurred previously in the SCE system[18] but could also result from external causes such as an earthquake, wildfire, sabotage, or electromagnetic pulse (EMP) event. The resulting outage is assumed to occur randomly throughout the year and to have a duration of two weeks – the estimated minimum time to deliver, install, and in-service the remotely located spare 500/115 kV transformer and to also repair associated bus work, structures and/or and transformer auxiliary equipment that could have been damaged. During an extreme HILP event, a 2-week outage assumption likely understates the recovery time, but the minimum time is assumed to limit the impact of this single metric on the overall analysis. A catastrophic failure of this type could take a period of several months to recover from and return to the pre-event state. The installed Valley Substation spare and offsite spare transformers are then assumed to be in service to serve the Valley South System load. System tie-lines (when available) are used to transfer load to adjacent systems during the interim period before service is restored to the Valley South System in order to minimize the customer impact of the outage.
- Flexibility 2-2 (Flex-2-2) – amount of LAR under a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other. The bus work is assumed to remain operable, as are the Valley North transformers, so the spare transformer is assumed to be available to serve load in the Valley South System. System tie-lines would be utilized to reduce LAR. Like Flex-2-1, the coincident transformer outages are assumed to occur randomly throughout the year and to have a duration of two weeks – the estimated minimum time to deliver, install, and in-service the remotely stored spare Valley transformer to restore full transformation capacity to Valley South. System tie-lines are used (when available) to transfer load to adjacent systems during the period before full Valley South system transformation capacity is restored in order to minimize the customer impact of the outage. The difference between Flex 2-2 and Flex-2-1 metrics is that, under a Flex 2-2 scenario, one transformer continues to be available to serve Valley South load whereas in the Flex-2-1 scenario, no transformers are available.

As described in more detail in Section 6.4 and summarized in Table ES-1, the metrics demonstrate the effectiveness of each of the alternatives in addressing the capacity, reliability, and resiliency needs in the areas served by the Valley South System in its current configuration over both short term and long-term horizons.

[18] Three SCE AA substations (Vincent, Mira Loma, and El Dorado) have experienced similar events in the past 20 years.

Table ES-1 –Performance Improvements through 2028 and 2048 for All Alternatives

Alternative	Results Through 2028		Results Through 2048	
	Capacity Improvement	Reliability/ Resiliency Improvement	Capacity Improvement	Reliability/ Resiliency Improvement
No Project	0%	0%	0%	0%
Alberhill System Project	100%	99%	99%	97%
SDG&E	100%	87%	99%	82%
SCE Orange County	99%	86%	93%	80%
Menifee	100%	79%	92%	74%
Mira Loma	100%	36%	77%	34%
Valley South to Valley North	100%	3%	78%	6%
Valley South to Valley North to Vista	100%	3%	89%	6%
Centralized BESS in Valley South	100%	1%	100%	4%
Valley South to Valley North and Distributed BESS in Valley South	100%	3%	81%	7%
SDG&E and Centralized BESS in Valley South	100%	87%	100%	83%
Mira Loma and Centralized BESS in Valley South	100%	36%	100%	35%
Valley South to Valley North and Centralized BESS in Valley South and Valley North	100%	3%	95%	6%
Valley South to Valley North to Vista and Centralized BESS in Valley South	100%	3%	92%	6%
Note: Performance improvements for each alternative represent the percentage of LAR reductions over the No Project Scenario. LAR N-0 and LAR N-1 are capacity metrics, while Flex-1, Flex 2-1, and Flex-2-2 are reliability/resiliency metrics.				

Because all of the system alternatives were designed to meet the system capacity needs over at least the initial ten-year project planning horizon, very little difference was shown among the alternatives from the perspective of capacity-related metrics LAR (N-0) and LAR (N-1) through 2028 (as evidenced by all alternatives showing at least an 99% capacity improvement in this period).[19] However, the reliability/resiliency driven Flex-1 and Flex-2 metrics clearly differentiated among the project alternatives, particularly in revealing the relative effectiveness of the system tie-lines (as evidenced by the broad range of reliability/resiliency improvements through 2028 and 2048).

[19] The alternatives that merely transfer load from one system to another without introducing a new substation sourcing power from the bulk electric system are not as strong on capacity related metrics beyond 2028 and would need to be augmented with DERs or some other project solution to meet system planning criteria much beyond this initial ten-year planning horizon.

Alternatives that would construct new substations, and therefore new transformation capacity (such as the ASP, SDG&E, and SCE Orange County) performed well with respect to both the capacity and reliability/resiliency metrics, since they transfer a large quantity of load from the Valley South System, and have the ability to take on additional load (through the use of the system tie-lines) during planned or unplanned outages. Generally, projects that included construction of new transmission substations showed the greatest overall improvement in reliability/resiliency metrics among the alternatives.

Alternatives that would transfer load from the Valley South System to an adjacent system, such as the Valley South to Valley North and Valley South to Valley North to Vista alternatives, were shown to perform moderately well in capacity improvement. However, they did not perform well in the reliability/resiliency category due to the lack of robust system tie-lines and the resulting lack of ability to accommodate additional load transfers to adjacent systems from Valley South during planned or unplanned outages.

Mira Loma performs well through 2028 from a capacity perspective, since the initial transfer of substations provides enough transformer capacity margin to the Valley South System for the 10-year planning horizon (2028). However, the system-tie lines created by this alternative are limited in their ability to transfer supportive load out of the Valley South System for the potential double-circuit N-2 contingencies (i.e., the transferred load does not significantly alleviate the overloaded lines during the N-2 contingencies). Additionally, under a catastrophic event at the Valley Substation (Flex-2-1) the total amount of load that can be transferred out of the Valley South System to the new Mira Loma system is less than that of other substation-based alternatives. The poor long-term performance of the Mira Loma alternative is due to the limited N-0 capacity margin provided to the Valley South System, because the Valley South System transformers would again become overloaded in 2031. This is the earliest date among all of the alternatives that the Valley South System transformers are projected to again be overloaded.

The Menifee alternative, despite including a new source substation, does not perform as well as the ASP, SCE Orange County, or SDG&E substation alternatives with respect to the reliability/resiliency metrics. This is because the location of the Menifee alternative substation, effectively adjacent to Valley Substation, does not allow for the creation of system tie-lines that are effective in reducing the impact of the line and transformer outages considered in the Flex-1 and Flex-2 metrics. This limitation and its cause are addressed further below and in Section 8.2.1 in discussing the cost-benefit analysis performance of this alternative. Additionally, Menifee is a less effective system solution than these other alternatives due to the proximity of the Menifee substation to the Valley Substation and resulting vulnerability to external events affecting both stations. This limitation is not reflected in the metrics because the impact of the assumed Flex-2 scenarios is confined to the boundaries of the Valley Substation.

Compliance with SCE Planning Criteria

Table ES-2 illustrates how alternatives compare in meeting requirements of SCE's Subtransmission Planning Criteria and Guidelines. This table indicates the alternatives which result in transformer overloads (and identifies the year of the overload), and the number of N-0 and N-1 line overloads through 2048; any of these overloads represent a violation of SCE's planning criteria. The alternatives which do not result in transformer overloads, and have limited

N-0 and N-1 line violations, are more robust, and are more capable of meeting the planning criteria over a longer time frame than those with transformer overloads and line violations. The ASP and the majority of the hybrid alternatives are the only alternatives which do not result in transformer overloads through 2048 (the BESSs associated with the hybrid alternatives were sized to mitigate transformer overloads). While project scope was included to address line violations for N-0 and N-1 conditions through 2028 for all alternatives, by 2048 the number of N-1 violations significantly increases for some alternatives, such as SCE Orange County, Menifee, all of the alternatives that include a Valley South to Valley North load transfer, and Mira Loma. While these violations can be remedied through future projects (typically reconductor or complete rebuild of the lines), the sheer number of line violations for these alternatives demonstrates the relative ineffectiveness of several of these alternatives during N-1 conditions over the long-term.

Additionally, the system analysis demonstrates that several of the alternatives (Centralized BESS in Valley South, Menifee and all of the Valley South to Valley North alternatives), do not satisfy the project objective of achieving VS system compliance with the subtransmission planning criteria associated with having system tie-line capacity to transfer load to adjacent systems when needed to mitigate the potential loss of service to customers in Valley South (see Table 4-1).

Table ES-2 – Planning Criteria Violations for All Alternatives

Alternative	Year of Transformer Overload	Number of N-0 Line Violations Through 2048	Number of N-1 Line Violations Through 2048
Centralized BESS in Valley South	N/A	0	0
SDG&E and Centralized BESS in Valley South	N/A	0	0
Mira Loma and Centralized BESS in Valley South	N/A	0	1
Valley South to Valley North and Centralized BESS in Valley South and Valley North	N/A	0	5
Alberhill System Project	N/A	1 (in 2046)	3
Menifee	VS: 2043	0	6
Valley South to Valley North to Vista and Centralized BESS in Valley South	VN: 2041	0	5
Valley South to Valley North to Vista	VN: 2041	0	0
	VS: 2043	0	6
SDG&E	VS: 2040	0	0
SCE Orange County	VS: 2040	0	4
Valley South to Valley North	VN: 2037	0	0
	VS: 2043	0	6
Valley South to Valley North and Distributed BESS in Valley South	VN: 2037	0	5
Mira Loma	VS: 2031	0	10

Note: This table is organized to illustrate how effective each alternative is in meeting SCE Subtransmission Planning Criteria and Guidelines over the long-term (through 2048). Alternatives are ordered according to their ability to provide adequate transformation capacity, which could be considered the most critical criterion to meet, given that adequate transformer capacity is essential in meeting customer load demands, and a lack of this capacity is typically the most costly to remedy. The alternatives are then ranked by N-0 line violations, which can be considered the next most critical criterion, since these overloads occur under normal operating conditions, as opposed to N-1 violations, which occur only under abnormal operating conditions.

Note: Voltage violations are not included in this table. The amount of load- at- risk from these violations is small compared to the load- at- risk due to line overload violations.

Siting and Routing

Siting and routing studies were performed for each of the alternatives, consistent with SCE's project siting and routing process. The siting and routing studies identified preferred substation sites and line routes, which were used to assess risk (e.g., agency permitting delays; uncertainty in the extent of licensing and public opposition; scope within wildfire areas; etc.), understand potential environmental impacts, and estimate associated costs for each of the project alternatives. While all alternatives reviewed are expected to be feasible based on the level of analysis performed, SCE determined that there are substantial differences in the complexity and risk associated with individual alternatives. These factors are reflected, to the extent possible, in the cost estimates for alternatives and are discussed qualitatively as part of this Planning Study. It is important to note that some of the alternatives are expected to have substantial challenges in licensing and permitting due to the specific nature of the routes and prior experience with affected communities, and because they have not yet been subject to California Environmental Quality Act (CEQA) review. SCE intentionally limited the extent to which it monetized the risk of delays and higher costs associated with siting, routing and licensing risk to ensure that the system performance merits of individual alternatives would not be discounted by subjective judgements of cost and schedule. For example, in the cost/benefit models presented here, all projects are assumed to be in service in 2022, at the time of the project need, while, in reality, there would likely be considerable differences among alternatives in terms of in-service date. See Section 7.0 Siting and Routing and Section 9.0 Risk Assessment, for additional information.

Cost Estimates

Project cost estimates were developed for each alternative at a level of confidence commensurate with a feasibility study level of design and analysis (e.g., Association for the Advancement of Cost Engineering (AACE) Level 3/4). Environmental monitoring and mitigation costs that are driven by specific siting and routing factors were included for each project alternative. The estimates included provisions for contingency and risk consistent with the level of development and design conducted to date and SCE's standard risk assessment and quantification process. For projects incorporating BESS, market participation revenues were applied to offset costs.

ASP costs are based on SCE's Direct Testimony Supporting its Application for a Certificate of Public Convenience and Necessity to Construct the ASP, dated July 17, 2017 (SCE Amended Cost Testimony)[20], and were adjusted to account for ongoing licensing costs, and the escalation from 2017 dollars to 2019 dollars. As the ASP is the only solution that has undergone significant design, environmental analysis, and project engineering to date, the remaining alternatives suffer from higher cost uncertainty due to the lack of environmental analysis, licensing, and engineering design efforts. Importantly, uncertainty costs were capped at 50% in accordance with expected accuracy of Level 3/4 AACE cost estimates, to limit the impact of uncertainty on study results. However, SCE's experience is that project costs for projects that have not been through the complete process of development, design, licensing, and stakeholder engagement can change by more than 50% when advancing to the execution stage. The risks of higher costs are therefore addressed on a qualitative basis elsewhere in the Planning Study. See Section 8.1.1 Costs and Section 9.0 Risk Assessment for additional information.

[20] See Table IV-1, page 25 of Section IV, "Southern California Edison Company's Direct Testimony Regarding the Maximum Prudent and Reasonable Cost of the Alberhill Project and the Qualifications of SCE Witness Gordon Tomaske".

In general, the projects that transfer load from one system to another via new subtransmission lines tend to be lowest in total cost, while those that incorporate new substations tend to be highest. Incremental battery additions to meet capacity needs are relatively inexpensive in early years; however, as the duration of overloads increases with time, the costs become substantial since large battery additions are required to meet energy needs. This is reflected in the BESS-only solution being the highest cost alternative in aggregate nominal dollars.

Monetization of System Performance Metrics

For the purpose of performing a cost-benefit analysis, the system performance metrics described above were monetized using 1) historical SCE line and transformer outage frequency data to probabilistically weight the loss of service metrics, and 2) the cost of service interruption data from SCE's Value of Service study (as presented in the SCE General Rate Case[21]). The primary objective of the Value of Service study is to estimate outage costs for various customer classes, using the well-established theoretical concept of "value-based reliability planning." This concept has been used in the utility industry for the past 30 years to measure the economic value of service reliability. The estimation of outage costs differs by customer classes: commercial and industrial outage costs are based on a direct-cost measurement, since these costs are easily measured, whereas residential outage costs are based on a willingness-to-pay survey.

Four capacity, reliability, and resiliency performance metrics were monetized to develop the benefits of each alternative: LAR under N-0 conditions; LAR under N-1 conditions; Flex-1; and Flex-2.[22] These metrics most accurately reflect the capacity, reliability, and resiliency benefit of the alternatives to SCE customers, most readily differentiate the alternatives, and can be probability weighted, monetized, and combined to reflect the overall benefit of alternatives[23]. When monetized, the LAR metrics are designated as Expected Energy Not Served (EENS) to reflect the assignment of probability weighting of the event scenarios and thus reflecting the actual expected unserved energy need for customers. Both costs and benefits are discounted to present day using financial parameters consistent with SCE's Present Value Revenue Requirement (PVRR)[24] model that reflects the overall present-day discounted effect of long-term investments on customer rates.

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[21] See WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A – pp. 12 – 109 – Southern California Edison: 2019 Value of Service Study.

[22] Additionally, improvements (i.e., reductions) in system losses were monetized based on projected future locational marginal pricing projections; however, the monetized values were low compared to the some of the other monetized system performance metrics and did not significantly distinguish among alternatives.

[23] Additionally, system losses are monetized. However, while different among the alternatives, the monetized values of the differences among the alternatives are small relative to the overall monetized benefits.

[24] PVRR is the ratepayer revenue required to repay an investment over its life converted into a common basis in current-year dollars. It is similar to a net present value. See Exhibit No SCE-01, Application A.13-10-XXX, West of Devers Upgrade Project, "Testimony Supporting Southern California Edison's Request for an Interim Decision Approving the Proposed Transaction", submitted October 25, 2013 before the Public Utilities Commission of the State of California.

The results of the analysis show that the majority of monetized benefit is associated with the EENS (N-0) and Flex-2 benefits. These benefits are associated with capacity and resiliency respectively. The value of the EENS (N-1) and Flex-1 benefits is low due to the localized impact of outages contributing to EENS (N-1) benefits and the relatively low probability of coincident outages and high loading conditions that contribute to substantial loss of service to customers. However, as discussed further below, should such an event occur, the cost and impact to customers would be severe for alternatives that do not provide adequate system tie-line capacity.

The monetized system benefits show that all evaluated alternatives demonstrate SCE customer benefits that well exceed the respective project cost.[25] The large magnitude of benefits compared to project costs is not unexpected, given the number of customers served by the Valley South System who would be impacted by electric service outages and the value customers place on their electric service.

As was the case for the system performance metrics (before monetization) described above, the alternatives that directly address the capacity need through the construction of adequate substation transformation capacity, such as the ASP, SDG&E, and SCE Orange County, and directly address the reliability/resiliency by diversifying the source power location and allowing the transfer of load out of Valley South through the use of system tie-lines provide the greatest overall benefits. These alternatives provide a means to initially transfer a large amount of load away from the Valley South System, thus increasing the operating margin of the Valley South System transformers and extending the timeline for when the transformers would again be at risk of becoming overloaded. In addition, the effectiveness of the system tie-lines created in these alternatives is maximized, since the new substations (with substantial transformation capacity) do not constrain the amount of additional load that can be transferred during planned or unplanned contingencies.

Similar to SDG&E, SCE Orange County and ASP, the Menifee alternative also creates a new source substation and thus also addresses much of the capacity and reliability/resiliency need. However, as discussed above, the Menifee alternative does not meet project objectives because its system tie-lines are ineffective in that they do not allow transfer of capacity out of Valley South beyond that which was initially transferred in implementing the initial project. Additionally, the location of the Menifee alternative substation would not be as effective in addressing the diversification of the locations of the source power to the region as that of ASP. The resiliency need represented in the metric is constrained to external and internal events that affect the equipment within the Valley Substation fence line. To the extent that a HILP event's impact could extend beyond the substation boundary (such as a large-scale wildfire, high wind event, or earthquake), the effectiveness of Menifee alternative in addressing the resiliency need would be substantially diminished relative to the performance that is represented by the metric.

[25] The cost to benefit analysis described herein differs from a traditional cost to benefit analysis in which the benefits realized represent offset or reduced future costs (i.e., provide a return on investment). For the purposes of this analysis, the costs reflect estimated project costs, whereas the benefits are to SCE's customer base and are associated with the avoidance of loss of electric service. This is an appropriate approach when analyzing utility-sponsored capital projects, where the utility has an obligation to provide safe and reliable electric service to customers and is therefore incentivized to maximize customer benefits, while also earning a fair return on investment through general rate increases.

Hybrid alternatives that use BESS to address long-term capacity shortfalls, along with system tie-lines, would provide the next highest level of overall benefits, whereas alternatives that transfer load from one existing system to another, such as the Valley South to Valley North and Valley South to Valley North to Vista alternatives, provide the least overall benefit. While these load-transfer alternatives perform reasonably well in improving short-term capacity (99% capacity improvement through 2028), they do not significantly improve reliability/resiliency during contingency events.

The very limited effectiveness of tie-lines for the Menifee and all of the Valley South to Valley North alternatives is because these alternatives essentially construct new subtransmission lines to transfer load away from the Valley South System on a permanent basis and the resulting system tie-lines only provide the opportunity to transfer this load back to the Valley South System in contrast to system tie-lines that would allow for bi-directional transfers. This is directly attributed to location of these alternatives (e.g., adjacent to or within Valley Substation). In order to create effective system tie-lines for these alternatives, additional distribution substations would need to be transferred out of Valley South. However, the distribution substations which are most accessible to transfer in these alternatives are substations through which power coming from the Valley South System transformers is routed before continuing on a path to serve the remaining distribution substations to the southern part of the system. Transferring these nearby substations, without significant additional 115 kV subtransmission line construction to effectively bypass them, would disrupt the design of the electrical network and adversely impact the ability to serve the more distant substations in the Valley South System. The amount of additional load that can be transferred during planned or unplanned contingencies is therefore limited. This is why it is much easier (and cost-effective) to create effective system tie-lines by transferring distribution substations at the periphery of the radial subtransmission system than by transferring distribution substations located near the source subtransmission substation. See Section 8.1.2 (Benefits) for additional information.

Benefit-to-Cost Results

As discussed in more detail in Section 8.2 of this Planning Study, the results of the cost/benefit analysis are presented in two ways: benefit-to-cost ratio and incremental cost-benefit analysis. The benefit-to-cost ratio is obtained by simply dividing the present value of monetized benefits by the PVRR, which represents total cost. The ranking of alternatives on this basis is shown in Table ES-3 below.

Table ES-3 – Benefit/Cost Analysis Results for All Alternatives

Alternative	PVRR ($M)	Benefits ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$4,282	9.0	Yes
SDG&E	$453	$4,001	8.9	Yes
Mira Loma	$309	$2,601	8.4	Yes
SDG&E and Centralized BESS in Valley South	$531	$4,041	7.6	Yes
Mira Loma and Centralized BESS in Valley South	$560	$3,132	5.6	Yes
SCE Orange County	$748	$4,021	5.4	Yes
Menifee	$331	$3,882	11.7	No
Valley South to Valley North	$207	$2,156	10.4	No
Valley South to Valley North and Distributed BESS in Valley South	$232	$2,165	9.3	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	$2,479	8.6	No
Valley South to Valley North to Vista	$290	$2,470	8.5	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	$2,542	6.9	No
Centralized BESS in Valley South	$525	$2,535	4.8	No

The project alternatives with highest benefit-to-cost ratios primarily achieve their rankings due to lower costs. These lower costs are driven in most cases by system solution limitations that do not enable the projects to fully satisfy project objectives. These limitations are also reflected in lower benefits. For example, as previously discussed, the Menifee and various Valley South to Valley North alternatives do not have effective system tie-lines. In another case (Mira Loma), the alternative meets project objectives but is a shorter term capacity solution and has system tie-lines that are not as effective as other source substation alternatives. When costs of longer-term capacity additions are considered, Mira Loma has a correspondingly lower benefit-to-cost ratio (the Mira Loma and Centralized BESS in Valley South alternative has a lower benefit to cost ratio than Mira Loma alone).

In performing a cost-benefit analysis of alternatives with widely disparate benefits, it is appropriate to perform an incremental cost-benefit analysis in which the incremental cost for higher-cost alternatives is weighed against the incremental benefits. This approach formalizes and quantifies the process used in the decisions made by consumers when they decide whether buying a higher priced product is “worth it.” On this incremental cost-benefit basis, the ASP is superior to all other alternatives, because it provides the most increase of benefits per unit of incremental cost. The

Menifee alternative was the second ranked alternative in this case. The ratio of the incremental benefits to incremental costs for ASP versus Menifee is 2.8, which demonstrates the cost effectiveness of increased spending to achieve greater benefits.

Sensitivity Analysis

SCE recognizes there is additional potential option value in alternatives with less expensive upfront costs that meet system needs for a shorter time frame over alternatives with higher upfront costs but longer- term system benefits. Specifically, should load develop slower than forecasted, the alternatives with lower front -end costs would incur future costs later than currently modeled, thus favorably affecting their cost-benefit performance. An analysis was performed to evaluate the sensitivity of the cost-benefit analysis results to uncertainty in the 30-year load forecast (see Section 5.4). SCE considered forecasts that were reflective of growth rates that were lower (0.6%/year) and higher (1.0%/year) compared to the base forecast growth rate (0.8%/year), by considering varying rates in DER growth and electrification. In each case, future incremental costs for the Hybrid alternatives incorporating BESS were adjusted to meet the forecasted load growth rate. For the lower forecast, the overall benefit -to -cost ratios were reduced. However, the relative results were not substantially changed other than a reduction in the performance of the Valley South to Valley North alternatives due to a reduction in their capacity benefits. For the higher load forecast, the overall benefits increased by a large amount but the relative results among the alternatives again do not change substantially. The Valley South to Valley North alternatives that rely on BESS additions are adversely affected due to the high costs of BESS additions to meet the greater capacity need. The ASP performs best in incremental benefit-to-cost ratio among alternatives in both lower and higher load forecast sensitivity case scenarios.

Lower upfront cost alternatives that incrementally add BESS to meet capacity needs could also benefit from lower than expected future costs through improvements in technology or market conditions. An additional sensitivity case was performed that reduced the costs of the BESS by 50% from the nominal costs assumed in the benefit-to-cost analysis. As expected, the benefit-to-cost ratios of the hybrid alternatives improved relative to conventional alternatives under this scenario; but even when the lower cost BESS and low load growth scenarios are combined, the substation-based alternatives perform best in overall benefit-to-cost ratio and the ASP continued have superior incremental benefit-to-cost performance.

Overall, this sensitivity analysis demonstrates that for reasonable downward adjustments in forecast load and BESS costs, the option value of deferring capital investments needed to meet system requirements is not likely to be substantial in light of the near-term need for system tie-lines to address the system reliability/resiliency needs. Further, the analysis demonstrates that the ASP and other conventional substation alternatives are robust from the perspective of addressing future load growth uncertainties, providing margin for higher future load growth from enhanced electrification scenarios beyond those considered in this analysis (see Section 9.4).

Risk Assessment

A risk assessment was performed to address other risks that were not monetized explicitly in the cost/benefit analysis (see Section 9.0). Among these risks, the most consequential is the uncertainty of licensing timelines and achievability for several of the alternatives. As discussed above, for simplicity, the accrual of project benefits for all alternatives were assumed to be concurrent with the 2022 project need date. While the ASP has been substantially vetted through regulatory and public scrutiny, the other alternatives have not, meaning the implementation costs for the other 12 alternatives could be even greater than those costs considered within the risk and uncertainty limits in the cost-benefit analysis. The licensing period associated with further development of alternatives, followed by CEQA review, would have the effect of reducing the benefits (due to the ongoing unavailability of system tie-lines) and increasing both the reliance on the current mitigation that is used to address the capacity shortfall and the risk to customers of loss of service due to a HILP event at Valley substation. For each year of delay, the reduction in overall benefits to customers would increase from a range of $4.3M to $148M.[26] If these likely licensing delays and associated cost and benefit impacts were to be monetized in the cost-benefit analysis, the alternatives with expected longer licensing durations would perform much less favorably than the ASP.

The consequence of project delays in risk of loss of service customers is masked to some extent in the assignment of probabilities to individual event scenarios. When one considers the real possibility of N-2 line and substation events occurring and that the probability of such an event is enhanced at periods of time when the systems are most vulnerable (high temperatures and high loading conditions), the consequences of these events are more apparent. For example, in considering the real possibility of a Flex-2-1 type event[27] occurring in 2028 on or near a peak load day without an appropriate project in place (i.e. one with adequate capacity and effective tie-lines and diverse location) the impact would be:

- Over 200,000 metered customers (>500,000 people) would lose service with no practical way to restore load in a timely manner
- The region would experience large scale economic impacts as well as disruption of public services
- Customers would experience a financial impact of several billion dollars (based on VoS study outage costs as well as published costs of recent widespread outages[28]).

Similarly, while the impact on N-2 line outages would be somewhat more localized, the consequences are also large. As an example, with no project in place, if a single 4-hour N-2 outage were to occur for the Valley-Auld #1 and Valley-Auld #2 115 kV lines (which have a number of common poles) on a peak day in 2028 approximately 35,000 customers would lose service for this period. Based on the VoS Study, the cost to customers of this single event would be on the order of $55M. Other credible line outage combinations would have a similar impact. In both the case of substation and line N-2 events this impact occurs, because without a project to

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[26] In 2022, the Centralized BESS in Valley South alternative provides $4.3M and the ASP provides $148M of benefits to customers. These benefits increase in subsequent years.

[27] Total loss of the power delivery to the Valley South System for a 2-week (minimum) outage to (remove, transport, and replace transformers, repair bus work, replace power and control cables, etc.)

[28] https://www.cnbc.com/2019/10/10/pge-power-outage-could-cost-the-california-economy-more-than-2-billion.html

add capacity and serve load in an alternative manner (e.g., through transfers using system tie-lines), load shedding would be required to mitigate overload conditions.

Recommendation

Based on the assessment described in this Planning Study, the recommended solution to solve the critical capacity, reliability, and resiliency needs of the Valley South System is the ASP. This recommendation is discussed in Section 10.0 of this Planning Study and is driven by the following factors[29]:

- Comprehensive Solution to Meeting Project Objectives: The Valley South System requires a comprehensive solution to address its distinct system needs. The system that has evolved from a series of short-term solutions is no longer adequate to serve SCE customers in this region and is critically deficient from the perspective of capacity, reliability, and resiliency. ASP provides a comprehensive, long term solution that most effectively meets all of the objectives defined at the onset of the project proceedings for the Valley South System.
- System Performance Improvement: ASP ranks highest among all of the alternatives in achieving over 97% improvement in the system capacity, reliability and resiliency performance in serving the needs of the region through 2048, while other alternatives achieve at most 83% of the available benefits. Similar differences are seen in performance over an initial ten -year period through 2028.

- Cost Effectiveness: In the cost-benefit analysis of several alternatives, ASP was found to have a benefit-to-cost ratio that was much greater than 1 and near the top of the range of alternatives. ASP was found to be superior to all other alternatives from the perspective of incremental benefit-to-cost ratio, which weighs the cost effectiveness of the higher benefits of ASP relative to other alternatives. Those projects ranked near or higher than ASP on an absolute benefit-to-cost basis do not meet project objectives, are very short-term solutions, and/or have substantial risks associated with licensing and implementation.
- Optionality and Risk: The ASP solution is more robust than the other alternatives from the perspective of potential variations in future load growth and other risks and uncertainties, and its cost effectiveness relative to other alternatives is not significantly affected in future planning scenarios with lower load or lower cost NWAs. ASP has lower risk of cost increases than alternatives that have not been subject to years of design, analysis, and stakeholder engagement as has been the case for ASP.
- Timeliness of Project Implementation: All project alternatives, other than ASP, would require extended periods for design, CEQA analysis, and public engagement in new communities, which will effectively preclude having a solution in place until late in the 10-year planning period. When the prospects for project timing are realistically considered, ASP further separates favorably from other alternatives under consideration.

[29] DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item I provides a more extensive basis for the ASP recommendation.

2.0 Problem Statement

SCE's Valley South System currently serves over 187,000 metered customers, representing approximately 560,000 individuals, nearly 6,000 of which are critical care customers. The 2018 adjusted peak demand, which includes weather adjustments to reflect a 1-in-5 year heat storm, is currently at 99.9% of the Valley South System's ultimate system design capacity (1,120 MVA). Forecasted load growth shows that peak demand is expected to exceed the rated transformer capacity of the system by the year 2022.[30]

The Valley South System has a unique combination of characteristics as compared to SCE's other subtransmission systems that result in reliability and resiliency challenges and contribute to the likelihood of occurrence and/or impact of events that lead to loss of service to customers.[31] The reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity margin, configuration, and size. In its current configuration, the Valley South System is the only SCE subtransmission system that does not have any system tie-lines to other systems. This results in an isolated system with negative impacts to reliability and resiliency due to the inability to transfer load during typically planned-for system contingency events and unplanned outages, including high-impact, low-probability events. The lack of capacity and absence of system tie-lines requires a solution to maintain the integrity of the electric system, and to prevent and mitigate customer service outages.

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[30] See Section 4.0 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.
[31] See Section 4.0 of DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B.

3.0 System Configuration

3.1. Existing Valley System

The San Jacinto Region of SCE's service territory covers approximately 1,200 square miles. It includes the cities of Lake Elsinore, Canyon Lake, Perris, Menifee, Murrieta, Murrieta Hot Springs, Temecula, Wildomar, and areas of unincorporated Riverside County. SCE serves the area from its Valley Substation located in Menifee, CA which has two distinct electrical systems, the Valley North and Valley South Systems. The San Jacinto Region is at the southern-most point of SCE's 50,000 square mile service territory. It is bounded to the west by the Santa Ana Mountains separating it from Orange County, to the east by the San Jacinto Mountains separating it from the Palm Springs area, and to the south by the San Diego Gas & Electric service territory. The region and its surrounding geography are shown in Figure 3-1.

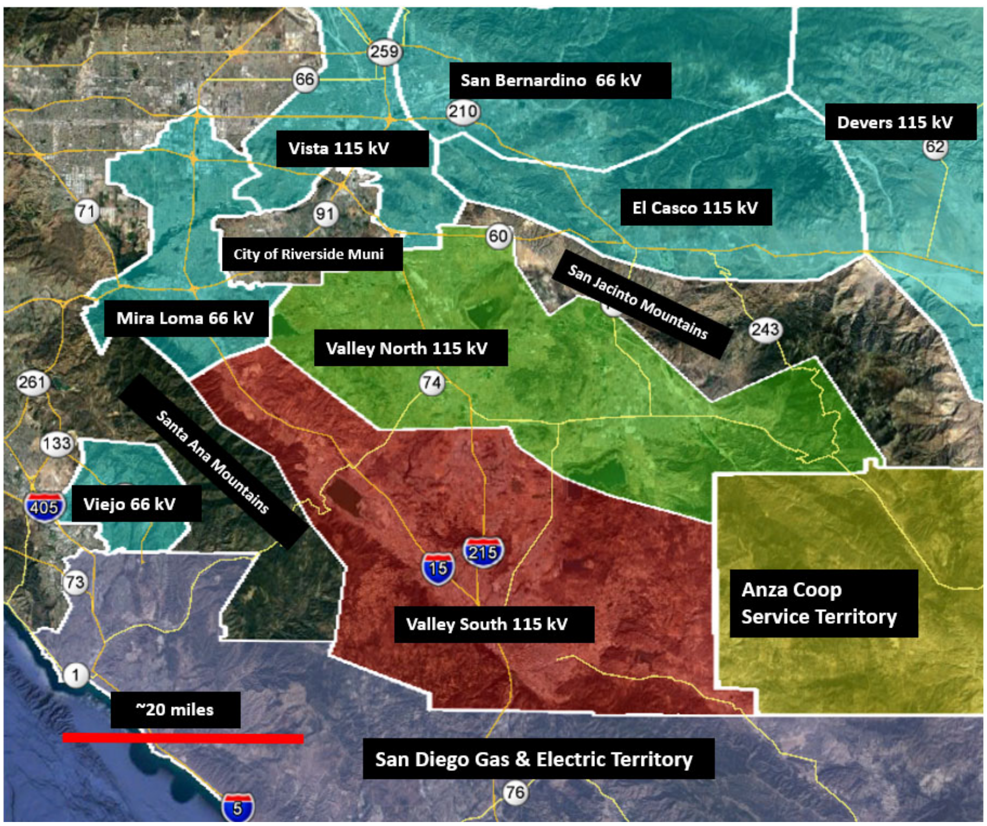

Figure 3-1 – San Jacinto Region Surrounding Geography and Electrical Systems

The region serves approximately 325,000 metered customers (Valley North and Valley South Systems combined) and provides electricity to approximately 1,000,000 people.[32] The customer

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[32] The entire SCE entire service territory serves electricity to approximately 5,000,000 metered customers representing approximately 15,000,000 residents or on average three persons per meter. https://newsroom.edison.com/internal_redirect/cms.ipressroom.com.s3.amazonaws.com/166/files/20190/About%20 SCE.pdf

base is largely composed of residential customers. The area served by Valley Substation is also home to many large businesses, including Abbott Vascular, Amazon Fulfillment, Pechanga Resort & Casino, Infineon Technologies, Skechers Shoes, Ross Distribution, and several city electric utility municipalities such as the Anza Electric Cooperative and the City of Moreno Valley. Valley Substation is SCE's largest load-serving substation in total transformer capacity installed, total load served, and total population served.

The source of power to the area passes through a single point of delivery at Valley Substation which is connected to the CAISO-controlled Bulk Electric System at the 500 kV voltage level. Valley Substation delivers power to its distribution substations through four 560 MVA 500/115 kV transformers, two serving the northern area (Valley North System) and two serving the southern area (Valley South System). Figure 3-2 shows the existing Valley North and Valley South System configuration.

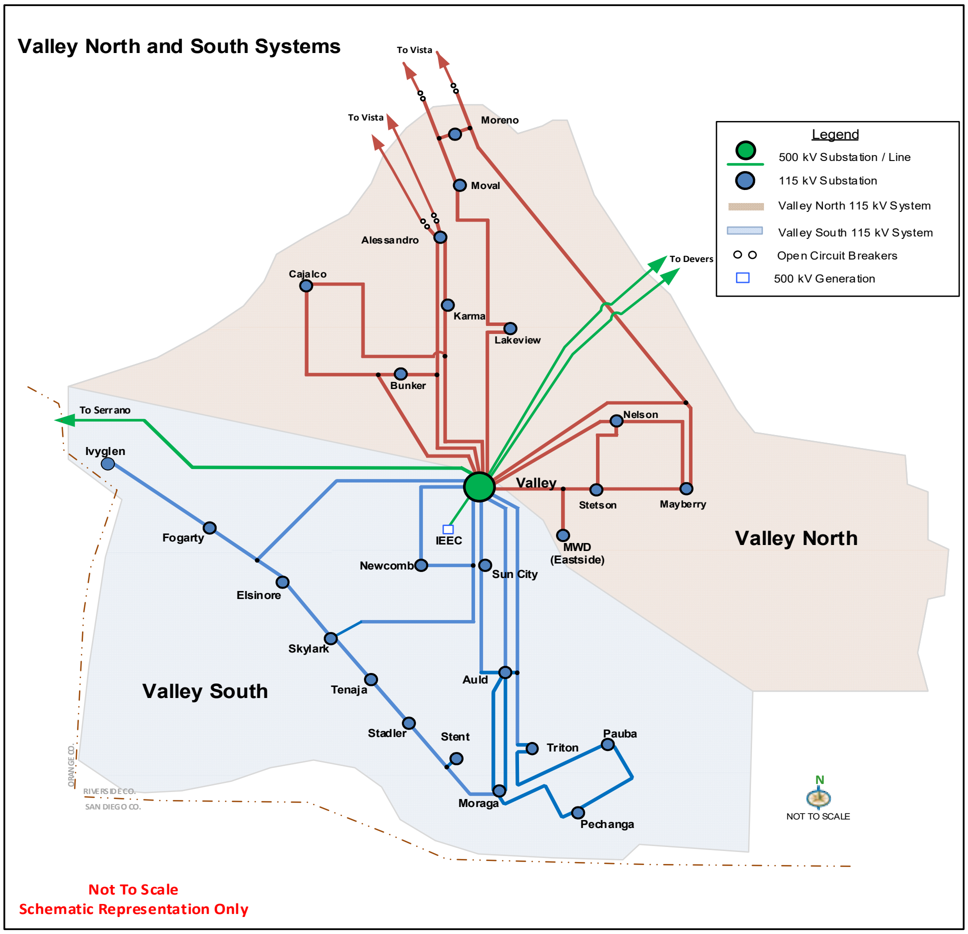

Figure 3-2 – Existing Valley North and Valley South Systems[33]

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[33] Figure does not reflect configuration changes associated with the Valley South project (recently placed in-service as of issuance of Revision 2 of this study) and the Valley Ivyglen project (under-construction as of issuance of Revision 2 of this study). These projects are reflected in the analysis described in this study.

3.2. *Substation Transformation Capacity and "Split" Systems*

SCE's current electrical system has a total of 43 load-serving "A-bank" transmission substations that transform voltage from the transmission level (220 kV or 500 kV) to the subtransmission level (66 kV or 115 kV) and then deliver power to multiple distribution substations. Of the 43 A-bank substations, 42 of them are served by 220 kV transmission source lines. These 42 substations are designed in a consistent manner which provides benefits for planning, operations, and maintenance and each is designed to serve up to 1,120 MVA of capacity through the use of four 280 MVA transformers.[34]

Valley Substation is SCE's only A-bank substation that uses 500/115 kV transformers and is the only system which has transformers rated at 560 MVA - twice the capacity of the typical transformers used at all of SCE's other A-bank substations. Significant procurement time, cost, and logistical challenges are required in order to transport and install these 500/115 kV transformers. Hence, long lead times are required to replace a failed unit (which is why an on-site, installed spare transformer is required).

The initial build-out of an SCE A-bank substation typically includes two transformers. Transformer capacity is then added (up to four transformers) based on projected load growth in the area served by the A-bank substation. By the time a fourth transformer bank is added at an A-bank substation, the existing subtransmission facilities are divided into two separately operated electrical systems (termed a "split system") with each system being served by two transformers. These two separately operated subtransmission "radial" systems are still both served from the same A-bank substation. However, because these subtransmission systems are electrically separate from each other, they are planned for independently as it relates to capacity, reliability, and resiliency. Figure 3-3 and Figure 3-4 illustrate the differences between A-bank substations that serve a single subtransmission system and those that serve split systems. The Valley System is an example of a split system with two electrically separate subtransmission systems (Valley North and Valley South) served from the same A-bank substation, Valley Substation.

There are several reasons related specifically to reliability and resiliency for splitting systems by the time that a fourth transformer is added. These reasons include reducing how many customers are affected when an electrical disturbance event occurs and limiting short-circuit current values that could otherwise increase beyond equipment ratings when four transformers operate electrically in parallel. Per SCE subtransmission planning guidelines discussed in Section 4.3 of this study, it is SCE's practice, consistent with good engineering practice for radial system design, to incorporate system tie-lines into a split system design to ensure that each of the newly formed radial electrical systems maintains the ability to transfer distribution substations from one system to another. These system tie-lines are commonly used to address system conditions resulting from planned or unplanned outages of either an A-bank substation transformer or of subtransmission

[34] Using standard transformer sizes allows for spare transformers to be maintained in inventory at strategic locations, which minimizes inventory requirements and maximizes the efficiency in mobilizing replacements following transformer failures.

lines to avoid overload conditions on the remaining A-bank transformers and/or subtransmission lines within that system and to provide operational flexibility. The Valley South System currently does not have system tie-lines as elaborated on and described in Section B.2 of Appendix B.

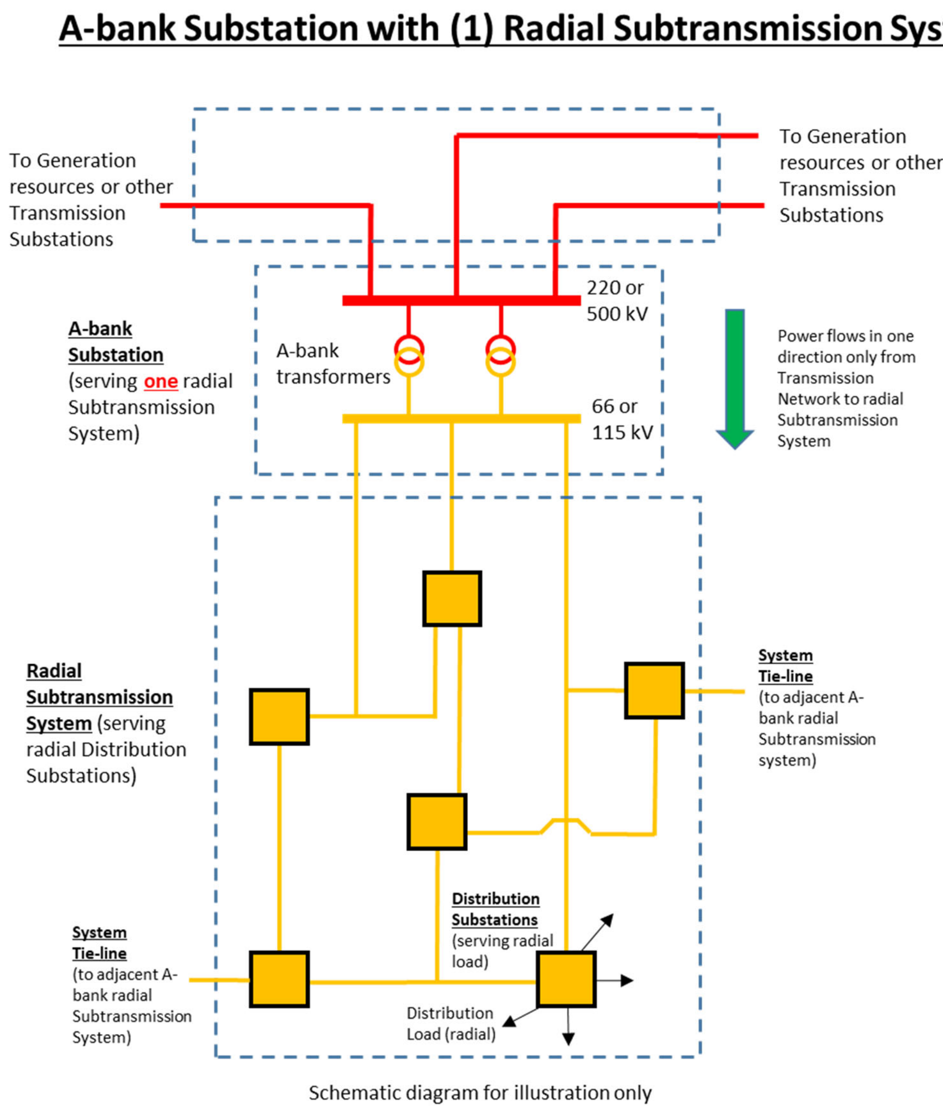

Figure 3-3 – A-bank Substation with a Single Radial Subtransmission System

A-bank Substation with (2) Radial Subtransmission System (or "Split System")

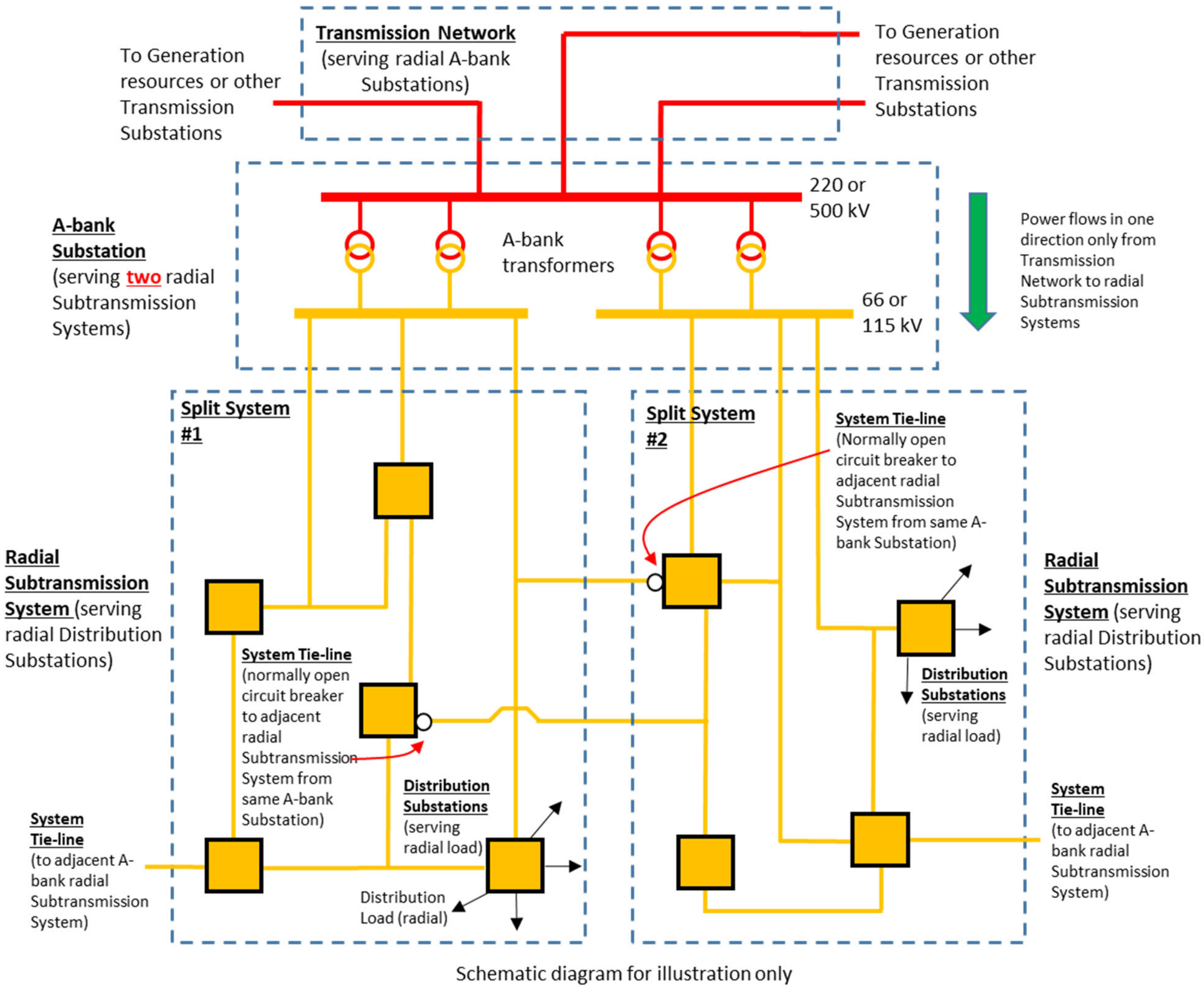

Figure 3-4 – A-bank Substation with Split Radial Subtransmission Systems

3.3. Comparison of Valley South System with Other SCE Subtransmission Systems

SCE has a total of 56 distinct subtransmission electrical systems served from its 43 A-bank substations (resulting from a portion of its A-bank substations operating in a "split system" configuration). Of these 56 electrical systems, all but four are served in a radial[35] manner. The Valley South System and the Valley North System are split systems served by the Valley A-bank Substation.

The Valley South System is unique in that it is the *only* one of these 56 distinct electrical systems without system tie-lines to another 115 kV subtransmission system. This condition resulted from a unique combination of events in the system's history that is chronicled in the *History of the Valley Systems* in Appendix B of this Planning Study. The lack of tie-lines that resulted from this evolution was not considered desirable or acceptable for the long term; however, due to the significant load growth that was occurring, SCE took temporary exception to its preferred, consistent, and prudent practice of including system tie-lines in its design of radial systems with an expectation that a long-term solution would be planned and implemented.

SCE provided data on Valley South System characteristics that challenge reliability and/or resiliency[36], contributing to the likelihood of occurrence and/or impact of events that lead to loss of service to customers. These characteristics, when compared to SCE's other 55 subtransmission systems, demonstrate that no other SCE subtransmission planning area has a similar cumulative combination of characteristics that lead to the reliability and resiliency challenges that the Valley South System faces.

The reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity margin, configuration, and size that make the Valley South subtransmission system much more vulnerable to future reliability problems than any other SCE subtransmission system. Specifically, in its current status, the Valley South System operates at or very close to its maximum operating limits, has no connections (system tie-lines) to other systems, and represents the largest concentration of customers on a single substation in SCE's entire system. These characteristics threaten the future ability of the Valley South System to serve load under both normal and abnormal system conditions. In the specific case of a catastrophic event (abnormal condition such as a major fire or incident at Valley Substation) SCE's ability to maintain service or to restore power in the event of an outage is significantly limited by the concentration of source power in a single location at Valley Substation.

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[35] There are two sets of networked substations included in the 56 distinct systems: the Antelope and Bailey 66 kV Systems and the Victor and Kramer 115 kV Systems. In each example, both of the electrical systems are located adjacent to each other and serve largely rural areas. In lieu of constructing a significant amount of new subtransmission lines to address any identified issues (under normal or abnormal system conditions) within each of the systems independently, reliability issues associated with lack of system ties between the split systems were able to be resolved by connecting the Antelope and Bailey Systems together and the Victor and Kramer Systems together and operating each in parallel with the CAISO-controlled bulk electric system.

[36] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B.

4.0 Planning Criteria and Process

4.1. Planning Process

The first step in SCE's annual distribution and subtransmission planning process is to develop peak load and DER forecasts for all distribution circuits, distribution substations, subtransmission lines, and load-serving transmission substations (A-bank substations). These forecasts span 10 years and evaluate peak load conditions to determine the impacts to SCE's distribution and subtransmission systems. Historically, peak load conditions were sufficient to determine criteria violations; however, as a result of increasing DER penetration in the distribution system, traditional peak load studies are no longer sufficient to capture criteria violations that may occur due to the DERs that impact the system outside of peak hours. As such, SCE now also evaluates high DER output conditions that are not coincident with peak load and the mitigations necessary to address criteria violations.

The SCE load forecast is derived from SCE's disaggregation of the California Energy Commission (CEC) annual California Energy Demand (CED) Forecast as part of the annual Integrated Energy Policy Report (IEPR) proceeding (see Section 5.0 Load Forecast). This forecast is provided at the bulk transmission level and is disaggregated down to the subtransmission and distribution levels.[37] DERs that consume and produce energy are incorporated at the lowest system level (e.g., distribution circuit level), and are used in the peak load forecast, as well as the separate high DER penetration analysis. After the load and DER forecasts are developed, the next step in SCE's planning process is to perform the necessary technical studies that determine whether the projected forecasts can be accommodated using existing infrastructure. SCE uses planning criteria as the basis for designing a reliable system. The planning criteria are based on equipment loading limits (termed "planned loading limits") that consider the effects of loading on thermal, voltage, and protection limits under normal and emergency conditions. The analysis includes comparing the expected forecast peak load under peak heat storm conditions over a 10-year period to these established planned loading limits.

When studies show that peak load or DER impacts are expected to exceed planned loading limits, potential solutions are identified to mitigate the risk of overloading equipment, which in turn serves to decrease the probability of failures and service interruptions that might affect many customers. As part of identifying solution alternatives, SCE first seeks to maximize the utilization of existing assets before developing projects that require capital expenditures to install new infrastructure.

4.2. Subtransmission Planning Criteria

SCE's Subtransmission Planning Criteria and Guidelines provide a basis for designing a reliable Subtransmission System taking into account continuity of service, as affected by system facility outages, and capital investment.[38] The Subtransmission Reliability Criteria are provided below.

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[37] For details on this methodology, see Section 3.0 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.
[38] SCE Subtransmission Planning Criteria and Guidelines 9/2015.

At a minimum, SCE's Subtransmission System shall be designed in order that the following occurrences do **not** result from a Likely Contingency[39]:

- Interruption of load except:
  - When served by a single Subtransmission System Component.
  - In the case of an Overlapping Outage of two subtransmission lines serving less than Major Subtransmission Load.
- Automatic under-frequency shedding of load.
- Operation of Subtransmission System Components at ampacity or power levels that exceed Likely Contingency Ratings.
- Voltage drop of more than 5.0% on high side substation load buses after available corrective action with Load Tap Change, switched capacitors, or voltage regulators.

These criteria are used when designing subtransmission systems and form the minimum acceptance criteria for performance of such systems in system studies. Unlikely Contingencies[40] are also studied to determine the effect on system performance. When such contingencies result in load interruption, loss of a generating source, risk of damage to SCE's electric facilities, or risk of Cascading Outages, projects to minimize the problems are considered. For all projects, assessments include estimated costs or benefits due to expected reliability levels provided by the alternatives under consideration.

4.3. Subtransmission Guidelines

The Subtransmission Guidelines provide general planning and design guidelines for components and operation of the subtransmission system. Components include subtransmission circuits, substations, transformers, busses, circuit breakers, protection devices, and volt-ampere reactive (VAR) control devices. Operational guidelines apply to practices such as load rolling, VAR correction, voltage regulation, curtailment, and relaying. Rather than exhaustively list the guidelines and requirements, those pertinent to the problem statement as it relates to the Valley South System are considered in this section, and are provided in Table 4-1. Note that as described in Table 4-1, SCE has had to take temporary exceptions to the Subtransmission Planning Criteria and Guidelines in order to comply with the mandate to continue to provide electricity in the face of significant local area economic growth and an expanding customer base while a comprehensive long-term solution was developed, permitted, and implemented.

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[39] A Likely Contingency is defined as follows: One generating unit is off/unavailable and then any one of the following occurs: (1) an outage of a single Subtransmission System Component; (2) an unscheduled outage of a single generating unit; (3) a simultaneous outage of two subtransmission circuits on the same pole and exposed to vehicular traffic when these circuits are the sole supply for a substation.

[40] An Unlikely Contingency is defined as follows: One generating unit is off/unavailable and then any one of the following occurs: (1) simultaneous outage of two subtransmission circuits; (2) an overlapping outage of any two generators or one generator and one line.

Table 4-1– Subtransmission Guidelines Related to Valley South

Section	Guideline	Relevance to Valley South
2.2.1	Sufficient 220/66 kV, 220/115 kV, or 500/115 kV transformer capacity will be provided, or adequate subtransmission tie line capacity with circuit breaker switching capability will be planned to limit or reduce the transformer loading in the event of a transformer bank outage.	The Valley South System is projected to exceed existing transformer capacity in 2022, and currently has zero tie-line capacity to limit transformer loading in the event of a transformer bank outage coincident with peak loading.
2.3.1	For the purpose of planning, 500 kV banks which serve radial load shall be planned as A-Banks, except using AA-Bank loading limits.	Valley Substation is an A-Bank substation serving radial load. Transformers are rated using AA-Bank loading limits.
2.3.1.1	Short-Term (1-hour) Contingency Loading Limit Maximum rating: Up to 160% of the Nameplate Rating provided that the load can be reduced to the Long-Term (24-hour) Emergency Loading Limit in one hour.	The Valley Substation spare transformer is currently utilized as necessary to temporarily relieve load on the two normally in-service Valley South transformers during peak loading. The spare is placed into service whenever the load on the substation exceeds 80% (896 MVA), in order to keep the total load on a single transformer under 160% (i.e., the Short-Term Contingency Loading Limit) in the event there is an unplanned outage of one of the transformers.

Section	Guideline	Relevance to Valley South
2.3.1.2	One three-phase 500/115 kV spare transformer will be provided on site at each 500/115 kV substation.	The Valley Substation spare transformer (which is shared among Valley North and Valley South) is currently utilized as necessary to temporarily relieve load on the two normally in-service Valley South transformers during peak loading. Thus, during peak loading scenarios, the spare transformer is not immediately available to serve its intended function as a replacement unit for an out-of-service transformer, and is therefore not available at all times if needed as a spare for the Valley North System.
2.3.2.1.A	All Facilities in Service: Adequate transformer capacity shall be provided to serve the maximum coincident customer loads (including 1-in-5 year heat storm conditions)…	Valley South System transformer capacity is projected to be exceeded by year 2022.
2.3.2.1.B	Contingency Outages: Adequate transformer capacity and load rolling facilities shall be provided to prevent damage to equipment and to limit customer outages to Brief Interruptions…	The Valley South System currently has no system tie-lines to any other system, and therefore has zero tie-line capacity available to roll load.
2.3.2.4	To avoid Protracted Interruption of Load, tie lines with normally open supervisory controlled circuit breakers will be provided to restore service to customers that have been dropped automatically to meet short-term Likely Contingency loading limits, and to reduce A-Bank load to the long-term Likely Contingency loading level.	The Valley South System currently has no system tie-lines to any other system, and therefore has zero tie-line capacity.

5.0 Load Forecast

SCE annually forecasts load, on a 10-year planning time horizon, to assess system capacity and reliability given projected future load growth. To validate this load forecast, Quanta Technology was contracted to perform two independent load forecasts. The load forecasts prepared for this study indicate that, under 1-in-5 year heat storm conditions, the Valley South System will exceed the ultimate design capacity of the existing transformers as early as the year 2022.

5.1. SCE Load Forecast Methodology

SCE develops its load forecast as the first step in its distribution and subtransmission planning process. The forecast spans 10 years and determines peak load using customer load growth and DER forecasts, including energy efficiency, energy storage, demand response, plug-in electric vehicles, and distributed generation such as solar photovoltaic (PV). The forecast is based on peak load collected from historical data, normalized to a common temperature base in order to account for variations in peak temperatures from year to year. In addition to a normalized 10-year forecast, the methodology also produces a forecast adjusted for 1-in-5-year heat storm conditions.

SCE uses the CEC's IEPR-derived CED forecasts to ultimately determine its base load growth forecast at the distribution circuit level. As the IEPR forecast is provided to the utilities at a system or large planning area level, SCE must disaggregate this forecast to provide the granularity necessary to account for local-area specific electrical needs. SCE utilizes its own customer data from its advanced metering infrastructure (AMI) to inform its disaggregation of the CEC IEPR forecast. Where appropriate, SCE may also incorporate additional load growth that may not have been fully reflected in the CED forecasts (e.g., cannabis cultivation load growth).[41]

A detailed discussion of SCE's Load Forecast is included in the supplemental data request submittals.[42]

5.2. Quanta Technology Load Forecast Methodology

The first method Quanta Technology used to forecast load is referred to as the Conventional method. Historical substation load data provided by SCE was normalized to a peak 1-in-2 year temperature for the region in order to place all distribution substation load data at the same

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[41] SCE participates in the CPUC's Distribution Forecasting Working Group to discuss, review, and approve, among other topics, the methodologies to disaggregate load and DERs to the distribution circuit level.

[42] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.

reference temperature.[43] These adjusted data were then used to compute horizon-year[44] load growth based on curve-fitting. The growth in load was then adjusted further by considering an increase in load due to non-traditional developments (e.g., cannabis cultivation), as well as an increase in load due to incremental growth in residential density (i.e., more multi-family homes than single family homes are built). Growth of DERs was accounted for by considering that these resources are part of historic load data and considering that the historic trend of DER development will continue in the future.

For each distribution substation, a Gompertz curve fit was developed to estimate the forecasted load at all intermediate years between 2018 and the horizon-year (i.e., 2048). The aggregate of all distribution substation forecasts was then used to compute a coincident horizon year load[45] for the Valley North and Valley South Systems. The aggregate forecasts were then adjusted to account for 1-in-5 year heat storms at the Valley North and South System level.

The second method Quanta Technology used to forecast load is referred to as Spatial Load Forecasting (SLF). This method involves the forecasting of peak load, customer count, and customer energy consumption within a particular needs area. The geographical region is divided into sub-areas, each of which is analyzed individually to forecast customer count, peak electrical demand, and annual customer energy consumption. Customer count forecasts are based on an analysis of zoning and land-use data within the sub-area. Customer peak demand and energy consumption is based on actual AMI data and a consideration of typical area building energy consumption (e.g., kWh per residential customer, kWh per commercial customer, etc.). Non-traditional factors that may affect electrical load growth, such as photovoltaic (PV), electric vehicle (EV) adoption, and energy efficiency (EE) are incorporated by disaggregating the CED forecast and applying appropriate growth factors at the smallest level of sub-division. Finally, the results are aggregated to forecast the net peak load on the system.

5.3. Load Forecast Results

Figure 5-1 shows the results of the three load forecasts. The red horizontal line in the graph represents the ultimate system design capacity of the Valley South System. The results show that all of the load forecasts predict that the Valley South transformers will overload in 2022.

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43 Load is highly correlated to temperature. As the peak demand for a given year may not fall on the exact day that a peak temperature is recorded, the peak load for each year of historical data must be normalized to a common temperature base in order to compare load from year to year. This is done using a 1-in-2 year temperature, consistent with industry practice.

44 In order to ensure optimal accuracy of the curve-fitting techniques used, a horizon year must be chosen. Typically, this horizon year is chosen to be very far into the future in comparison to the time period under study. For this analysis, a horizon year of 2048, or 30 years into the future, was chosen.

45 The actual aggregate produced a non-coincident horizon year load at the Valley North and Valley South systems. Coincidence factors were applied to adjust the loads to represent the total coincident load. See Quanta Technology Report *Load Forecasting for Alberhill System Project* for further discussion.

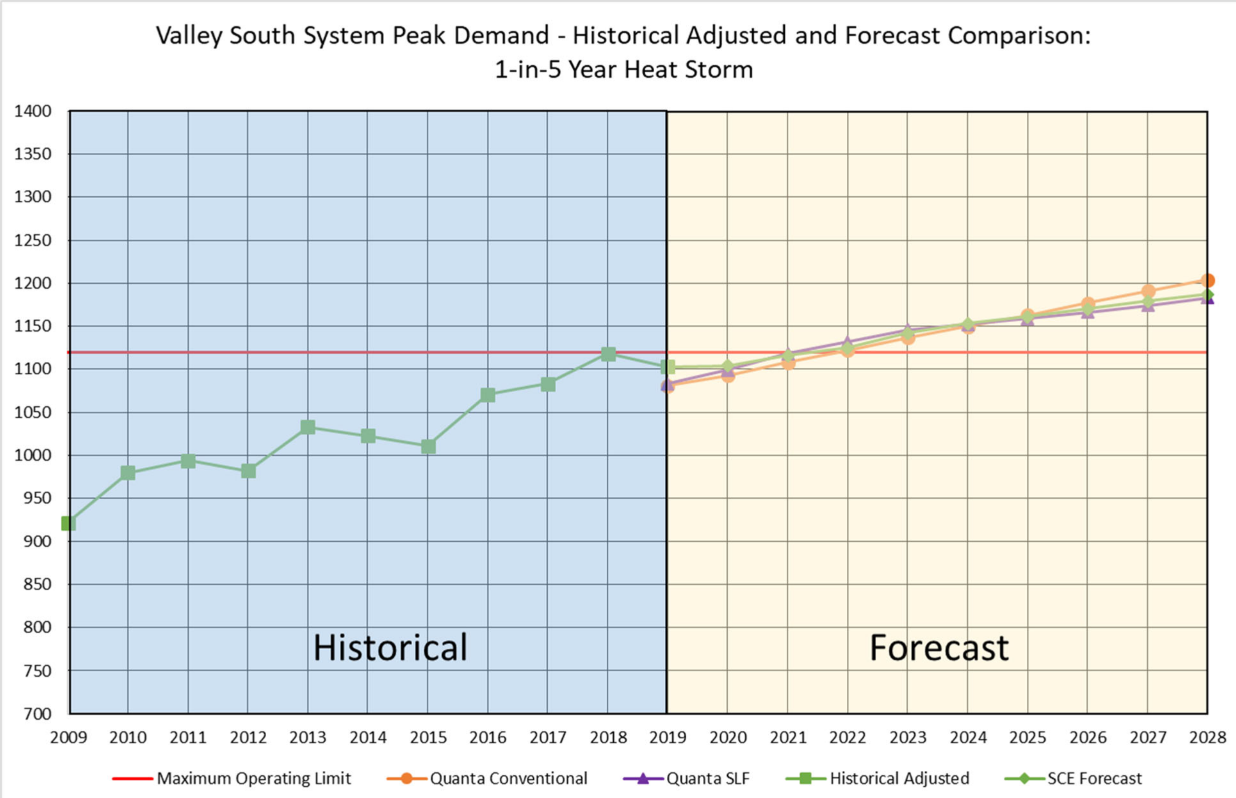

Figure 5-1 – Valley South System Peak Demand, Historical and Forecast

5.4. Load Forecast Extension to 30 Years

To support SCE's cost-benefit analysis, the Quanta SLF was used to forecast load beyond the 10-year planning horizon. Recall that the SLF looks at small, discrete areas (150 acres in size) and considers geo-referenced individual customer meter data (peak load), local land use information, and county and city master and specific development plans and thus is particularly well-suited among load forecasting methods for long term forecasts. Similar to the Quanta Technology Conventional Forecast, curve-fitting techniques were used for each of these small, discrete areas to forecast load for a full 30 years, roughly corresponding to the economic life of conventional transmission and distribution assets that make-up the ASP and all of the alternatives that meet the project objectives. Quanta Technology developed three forecasts based on this spatial analysis to support both a base case cost-benefit analysis as well as high and low load cases for sensitivity analysis. These three cases reflect varying rates of DER adoption. Because both upward and downward trends in economic conditions are expected over a 30-year forecast period, no additional variations in the forecasts were incorporated based on economic factors.

The first forecast ("Spatial Base") incorporates future DERs by assuming a continuing rate of DER adoption reflected in historical load growth and thus does not directly reflect future deviations in the existing trends in on-peak PV, building and vehicle electrification, energy storage (ES), energy efficiency (EE), or demand response (DR). Although it is possible that enhanced electrification rates could exceed future PV, ES, EE, and DR growth, for the purpose of this cost-benefit analysis, this Spatial Base forecast is considered to be the high load forecast, reflecting a scenario where increased growth rates for electrification effectively offset increases in growth rates for load-reducing DERs.

A mid-range ("Spatial Effective PV[46]") load forecast was developed by considering continuing changes in growth rates of DER adoption as reflected in the 2018 CED forecast. The adopted 2018 forecast only goes out to the year 2030. In order to extend IEPR load growth considerations to 2048, a regression method with a saturation tendency was applied to the individual IEPR-derived PV, EV, EE, and DR load impact forecasts. The forecast DER growth rates were determined through regression analysis, then applied to reduce the forecast load to account for expected increases in DER adoption beyond those reflected in historical trends. The Spatial Effective PV forecast also includes an adjustment to account for the expected effective on-peak contribution of installed customer-sited solar PV capacity for peak load reduction, adjusting the amount of generation based on time-of-day and general historical reliability metrics. This forecast is used as a base-case for the cost-benefit analysis as it is considered to represent the most likely future long-term load forecast scenario.

Finally, a low load forecast case ("Spatial PVWatts") was developed by incorporating the unadjusted extended CED forecast, using the IEPR-derived PV forecast (derived from the National Renewable Energy Laboratory DOE PVWatts PV generation modeling program) directly without the SCE adjustments for dependability. This low forecast is considered to be reflective of a future scenario where PV adoption, either on-peak or load-shifting, significantly outpaces electrification.

Figure 5-2 shows the three forecasts for the Valley South System used in the Uncertainty Analysis. For details on the 30-year extension of the load forecast, see Quanta Technology Report *Benefit Cost Analysis of Alternatives.*

[46] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A and Quanta Technology Report *Load Forecasting for Alberhill System Project* for a detailed description of Spatial Effective PV.

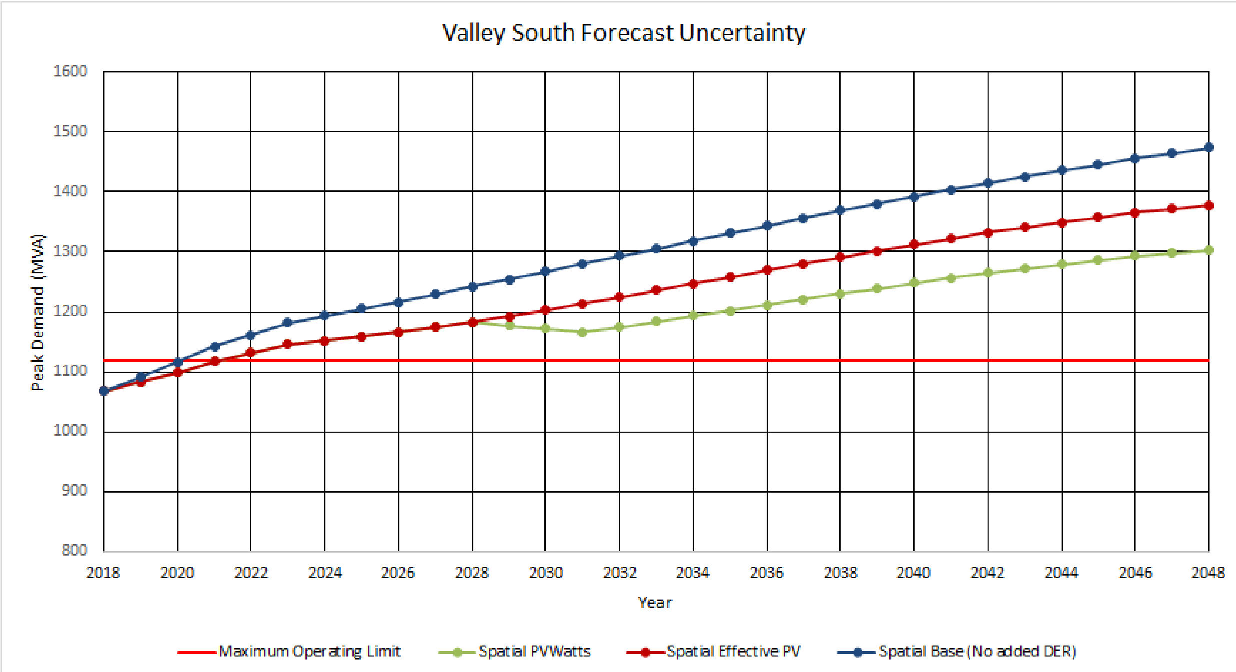

Figure 5-2 – 30-year Load Forecast with Uncertainty

The three forecasts were used to perform cost-benefit analyses for each of the alternatives, in order to assess if and how the results of the cost-benefit analysis would vary given a variance in the 30-year forecast. The alternatives were expected to score slightly differently based on either additional or fewer benefits accrued. For instance, when using the higher forecast (Spatial Base), alternatives that include capacity margin would tend to accrue more benefits. Conversely, in the lowest forecast (PV Watts), alternatives that are lower in cost may score higher, as those alternatives with capacity margin would accrue fewer benefits. Higher or lower forecasts also affect the reliability and resiliency related metrics in the cost benefit analysis as more or fewer customers are affected by the outage scenarios associated with the cost benefit metrics and capacity margin can affect the flexibility to mitigate these scenarios. The results of this uncertainty analysis are in Section 8.0.

6.0 Alternatives Development and Screening

SCE developed a comprehensive list of preliminary project alternatives based on a variety of inputs including: the direction of the CPUC in the Alberhill decision[47]; the previous assessment of alternatives in the Alberhill EIR; public and stakeholder engagement; and professional expertise. Preliminary project alternatives were evaluated qualitatively against project objectives and quantitatively using reliability and resiliency metrics to allow for a comparative assessment. All alternatives were designed to serve load at least through the horizon of the 10-year load forecast in accordance with the project objectives and SCE subtransmission planning criteria.

A total of 16 project alternatives were initially considered, including three Minimal Investment Alternatives, seven Conventional Alternatives (including the Alberhill System Project), one Non-Wires Alternative (NWA), and five Hybrid Alternatives that combine Conventional and NWA alternatives. This section briefly introduces the project alternatives, describes the performance metrics used for comparison, and presents the results.

6.1. Project Alternatives

Project alternatives were grouped into four categories based on the overall approach of the alternative. Minimal Investment Alternatives were considered as solutions that utilize existing equipment or make modest capital investments of <$25M to mitigate the issues under evaluation. Conventional Alternatives include transmission and/or subtransmission line and substation build outs, as well as system tie-lines to neighboring systems. NWAs include, for example, BESS in both centralized (transmission system level) and distributed (distribution system level) installations. Hybrid Alternatives are those that combined Conventional Alternatives with NWA. Appendix C provides a more detailed overview of each of the alternatives that were ultimately considered in the cost benefit analysis of alternatives.

The Conventional Alternatives were designed to accommodate the capacity need for the expected load forecast for the ten-year planning period but in most cases due to practical limitations[48] in the number of substations that could be transferred, the Conventional Alternatives were not able to satisfy the needs for the full 30 years of the cost-benefit analysis. In these cases, the shortfall in capacity is represented in the cost -benefit analysis as a reduction in benefits of the proposed solution. Alternatively, in the case of Hybrid Alternatives, the future capacity shortfall was met by incorporation of NWAs to the initial Conventional Alternatives.

NWAs are considered at both the subtransmission level (Centralized) or at the distribution level (Distributed) and, for the purpose of this Planning Study, BESS are used as a surrogate for all DERs that might ultimately be incorporated in Hybrid Alternatives. From a system perspective,

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[47] The CPUC directed SCE to supplement the existing record with "Cost/benefit analysis of several alternatives for: enhancing reliability and providing additional capacity including evaluation of energy storage, distributed energy resources, demand response or smart-grid solutions." (Decision 18-08-026)

[48] Practical considerations include the ability of the adjacent system to accommodate the load transfer as well as engineering judgement on the cost-effectiveness of larger scale system modifications required to increase the number of transferred substations.

energy storage and other DERs similarly serve to reduce system level loading at the level in the system in which they are installed and BESS represents a NWA option with minimal uncertainty from a cost and implementation risk standpoint (See Section 9.10). When the need date for the incremental capacity needs approaches, SCE can, under the appropriate regulatory framework at the time, build or source available front-of-the-meter and behind-the-meter DER technologies at market prices to meet these incremental capacity needs.

SCE also developed Hybrid Alternatives to satisfy the incremental capacity needs including NWAs that could be introduced incrementally as the remaining capacity need develops over time (e.g., Valley South to Valley North and Distributed BESS in Valley South). In such case, the additional capacity benefits are accrued but at a higher cost of meeting the capacity shortfall through NWAs. Each Hybrid alternative includes subtransmission scope which addresses some portion of the capacity need of the project by either transferring some number of the Valley South System distribution substations to either a new source substation or to an adjacent subtransmission system that has capacity margin. The number of substations that can be transferred in a solution is limited by the required scope of subtransmission work within the Valley South System to implement the transfer[49] and, in the case of a transfer to an existing adjacent subtransmission system, the capacity margin that exists to serve this new load in that adjacent system.

6.1.1. Minimal Investment Alternatives

Utilizing spare transformer for the Valley South System

This alternative considered temporarily placing the spare 500/115 kV transformer at the Valley Substation in service as needed to service the Valley South System under peak loading conditions, essentially continuing the current practice of the mitigation plan in place today. This alternative would also involve installation of a new spare 500/115 kV transformer (for a total of six transformers within Valley Substation). Implementation of this alternative would be challenging, if not infeasible, due to physical space constraints of Valley Substation and electrical system limitations associated with operating in this configuration.[50]

Operating existing Valley South System transformers above normal ratings

SCE's Subtransmission Planning Criteria and Guidelines allow operation of A-bank transformers above nameplate for periods of limited duration. This alternative involves utilizing the Valley South System transformers above normal ratings (i.e., intentionally operate them above the manufacturer nameplate ratings) to serve load in the Valley South System under peak loading conditions.

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[49] The subtransmission work that is associated with this load transfer must also leave lines in place to serve as system tie-lines between systems thus satisfying the system tie-line project objective.

[50] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item H for details related to short-circuit duty with three or more transformers operating in parallel at Valley Substation.

Load Shedding Relays

This alternative would utilize load shedding to maintain system reliability during stressed system conditions that result from peak load conditions that would otherwise exceed the ratings of the Valley South System transformers.

6.1.2. Conventional Alternatives

Alberhill System Project

The ASP would involve the construction of a new 1,120 MVA 500/115 kV substation in Riverside County. Approximately 3.3 miles of new 500 kV transmission line would be constructed to connect to SCE's existing Serrano-Valley 500 kV transmission line. Construction of approximately 20.4 miles of new 115 kV subtransmission line would be required to transfer the Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb Substations to the new Alberhill System.

SDG&E

This alternative would construct a new 230/115 kV system, anchored by a substation located in SCE territory, but provided power by SDG&E's 230 kV System.[51] SCE's existing Pechanga and Pauba Substations would be transferred to the new 230/115 kV system, which would be powered by looping in the existing SDG&E Talega-Escondido 230 kV transmission line. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

SCE Orange County

This alternative would construct a new 220/115 kV system, anchored by a new substation located in SCE territory. SCE's existing Stadler and Tenaja Substations would be transferred to this new system, which would be powered by looping in SCE's existing SONGS-Viejo 220 kV transmission line. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

Menifee

This alternative would construct a new 115 kV system, anchored by a new 500/115 kV substation at or near the existing site of the third-party owned Inland Empire Energy Center (IEEC) generation facility. SCE's existing Newcomb and Sun City Substations would be transferred to

[51] For the purposes of this Planning Study, the designation of SCE's 220 kV system voltage and the designation of SDG&E's 230 kV system voltage can be considered equivalent.

this new system, which would be powered by looping in SCE's existing Serrano-Valley 500 kV transmission line.

Mira Loma

This alternative would construct a new 220/115 kV system, anchored by a new 220/115 kV substation located in SCE territory near the existing Mira Loma Substation. SCE's existing Ivyglen and Fogarty Substations would be transferred to this new system, which would be powered by looping in one of SCE's existing 220 kV transmission lines serving Mira Loma Substation. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

VS to VN (Valley South to Valley North)

This alternative would transfer SCE's existing Newcomb and Sun City Substations from the Valley South System to the Valley North System. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

VS to VN to Vista (Valley South to Valley North to Vista)

This alternative would construct new 115 kV lines connected to the Valley North System bus at Valley Substation and would transfer SCE's existing Newcomb and Sun City Substations from the Valley South System to the Valley North System. Additionally, SCE's existing Moreno Substation would be transferred from the Valley North System to SCE's adjacent Vista 115 kV System by utilizing existing system ties between the Valley North System and the Vista 115 kV System. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

6.1.3. Non-Wires Alternatives

Centralized BESS in VS

This alternative would install two 115 kV connected BESS, one each near SCE's existing Pechanga and Auld Substations.

Although this alternative on its own does not meet all of the project objectives (specifically the creation of system tie-lines), SCE carried forward the Centralized BESS in VS in the analysis in order to investigate the relative cost-benefit performance of a BESS solution alone and when paired with a Conventional Alternative to demonstrate the benefit of the system tie-lines.

6.1.4. Hybrid Alternatives

Hybrid alternatives were developed by combining Conventional Alternatives and NWAs. The conventional solutions were chosen based on their ability to meet the 10-year load forecast and then paired with BESS to satisfy incremental capacity needs that develop over time.

Capacity margin above and beyond capacity provided by new transformation or the transfer of load in each of the Hybrid Alternatives is initially achieved through the construction of system tie-lines, as tie-lines can be engaged to alleviate a potential thermal or voltage violation on a subtransmission line. Then, consistent with planning criteria under normal (i.e., N-0) conditions, the BESSs were sized to mitigate capacity shortfalls in the Valley South and Valley North Systems over the 30-year load forecast. The initial battery installation therefore occurs when there is a projected capacity shortfall under normal conditions. This initial installation varies among the alternatives and is driven by the amount of margin that is provided by the corresponding conventional scope.

Unlike Conventional Alternatives, BESS include both a power (megawatt or MW) and energy (megawatt-hour or MWh) sizing component to meet capacity shortfalls. The power component corresponds to the amount of peak demand in excess of the transformer capacity in the systems, and the energy component corresponds to the total energy that would otherwise go unserved during times in which the transformer capacity is exceeded. The power component of the BESS was augmented for N-1 conditions (consistent with the Subtransmission Planning Criteria) by including an additional 10 MW of capacity.[52] Similarly, the energy component of the BESS was augmented for battery degradation (2% per year), and for N-1 conditions.[53]

The initial, and each subsequent BESS installation, is sized to meet the projected capacity need in the system for five years. For example, a BESS installed in 2037 would mitigate the projected capacity shortfall through 2042 at which point additional BESS capacity would be added. The battery installation schedules for each Hybrid Alternative are provided in Appendix C.

Valley South to Valley North and Distributed BESS in VS

This alternative would augment the Valley South to Valley North Alternative with three smaller 12 kV connected BESSs throughout the Valley South System, at the Auld, Elsinore, and Moraga 115/12 kV distribution substations. The BESS would be required in the 2043 timeframe. The size and need date of each BESS was determined by the local need. Note that from a system benefit perspective this alternative would be similar to the case where a specific, targeted Demand Side Management (DSM) or other Distributed Energy Resource (DER) program were to be implemented at the distribution system level.

SDG&E and Centralized BESS in VS

This alternative would augment the SDG&E Alternative with a centralized 115 kV connected BESS located near SCE’s existing Auld Substation. The BESS would be required in the 2039 timeframe.

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[52] SCE expects that the BESS installations would be comprised of modules of batteries connected to the system in blocks of 10 MW each. Typical N-1 assessments consider the unavailability of single system components (e.g., transformers, lines, generating units) and thus in this scenario, a single BESS module was considered unavailable.

[53] A duration of 5 hours is assumed for N-1 conditions. This equates to an additional 50 MWh (based on a 10 MW rating) of energy in each system (i.e., Valley South, Valley North, or both, depending on the alternative).

Mira Loma and Centralized BESS in VS

This alternative would augment the Mira Loma Alternative with a centralized 115 kV connected BESS located near SCE's existing Pechanga Substation. The BESS would be required in the 2031 timeframe.

VS to VN and Centralized BESS in VS and VN

This alternative would augment the VS to VN Alternative with two separate centralized 115 kV connected BESS installations (one near SCE's existing Pechanga Substation and one near SCE's existing Alessandro Substation). The BESS would be required in the 2043 and 2037 timeframes, respectively.

VS to VN to Vista and Centralized BESS in VS

This alternative would augment the VS to VN to Vista Alternative with a centralized 115 kV connected BESS near SCE's existing Pechanga Substation. The BESS would be required in the 2043 timeframe.

6.2. *Evaluation of Alternatives Using Project Objectives*

Each project was qualitatively evaluated against the Project Objectives detailed in SCE's Application for the ASP.

- Serve current and long-term projected electrical demand requirements in the Electrical Needs Area.
- Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer substations from the current Valley South System.
- Transfer (or otherwise relieve[54]) a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through the 10-year planning horizon.
- Provide safe and reliable electrical service consistent with the Company's Subtransmission Planning Criteria and Guidelines.
- Increase electrical system reliability by constructing a project in a location suitable to serve the Electrical Needs Area (i.e., the area served by the existing Valley South System).
- Meet project need while minimizing environmental impacts.
- Meet project need in a cost-effective manner.

Based on SCE's evaluation against these objectives, the three Minimal Investment Alternatives were eliminated from further quantitative analysis due to meeting only one or none of the project objectives. The Centralized BESS in Valley South alternative by itself also falls short of meeting the project objectives; however, as discussed, SCE carried forward a BESS-only alternative in the analysis in order to investigate the relative cost-benefit performance of these BESS solutions alone

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[54] Clarified from original objectives so as not to preclude non-wires alternatives.

and when paired with a Conventional Alternative to demonstrate the benefit of the system tie-lines. All of the Conventional Alternatives and Hybrid Alternatives were confirmed to meet the project objectives.[55]

6.3. System Performance Metrics

In order to compare the alternatives to one another on a quantitative basis, a time-series power flow analysis was performed for each alternative carried forward. The system was modelled and analyzed using the GE-PSLF (Positive Sequence Load Flow) analysis software. PSLF is a commonly used software tool used by power system engineers throughout the utility power systems industry, including many of the California utilities and the CAISO, to simulate electrical power transmission networks and evaluate system performance. The tool calculates load flows and identifies thermal overload and voltage violations based on violation criteria specified by the user. In this case, the model considers the existing Valley South and Valley North Systems and includes the pending Valley-Ivyglen and VSSP projects[56] which are both in construction and anticipated to be completed in 2022 and 2021, respectively. The 8,760 hour load shape of each system was utilized and scaled according to the 1-in-5 year adjusted peak demand given by the load forecast for each of the years under study. The specified analysis criteria listed below are consistent with the SCE subtransmission planning criteria described in Section 4.0 of this Planning Study.

- No potential for N-0 transformer overloads in the system.
- Voltage remains within 95%-105% of nominal system voltage under N-0 and N-1 operating configurations.
- Voltage deviations remain within established limits of +/-5% post contingency.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.

For each hour analyzed, the model determines how much, if any, load is required to be transferred to an adjacent system (if system tie-line capacity is available) or dropped (if system tie-line capacity is not available) in order to maintain the system within the specified operating limits. The dropped (or unserved) load is summed over the 8,760 hours of the year, for base and contingency conditions, over a 30-year span of the Planning Study to provide the basis for the majority of the metrics described below.

The alternatives were evaluated using the following system performance metrics. For each metric, the incremental improvement over the baseline was quantified for each of the project alternatives. Full details of these analyses can be found in Quanta Technology Report *Benefit Cost Analysis of Alternatives*.

- Load at Risk (LAR)
    - Quantified by the number of megawatt-hours (MWh) at risk during thermal overload and voltage violation periods.

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[55] Although the Conventional and Hybrid Alternatives currently meet the capacity requirements identified in the 10-year forecast, once licensed and constructed, several alternatives will no longer be able to meet this requirement as the load continues to increase beyond 2028.

[56] Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018).
VSSP, Valley South 115 kV Subtransmission Project, CPUC Decision 16-12-001 (issued December 1, 2016).

    - Calculated for N-0 and all possible N-1 contingencies.
    - For N-1 contingencies, credits the available system tie-line capacity that can be used to reduce LAR.
- Maximum Interrupted Power (IP)
    - Maximum power to be curtailed during thermal overload and voltage violation periods.
    - Calculated for N-0 and N-1 contingencies.
- Losses
    - Losses are treated as the active power losses in the Valley South System. New lines introduced by the scope of a project are included in the loss calculation.
- Flexibility 1 (Flex-1)
    - Accumulation of LAR for all N-2 contingencies. N-2 contingencies are only considered for lines that share common structures.
    - Credits the available system tie-line capacity that can be used to reduce LAR.
    - Results for each N-2 contingency simulation are probabilistically weighted to reflect the actual frequency of occurrence of N-2 contingencies.
- Flexibility 2 (Flex-2)
    - Flex-2-1
        - Amount of LAR in the Valley South System under a complete Valley Substation outage condition (loss of all transformers at Valley Substation) due to a high impact, low probability (HILP) event.
        - Similar to substation events that have occurred previously in the SCE system[57] and more broadly in the industry in which a single catastrophic transformer failure results in damage to an adjacent transformers and associated bus work and other facilities. A similar consequence could occur from an external event such as an earthquake, wildfire, sabotage or electromagnetic pulse (EMP).
        - LAR accumulated over a two-week period that is assumed to occur randomly throughout the year. The two-week recovery period is the minimum expected time to deliver, install, and in-service a remotely stored spare Valley System transformer and to repair associated bus work and other damage.
        - Credits the available system tie-line capacity that can be used to reduce LAR.
    - Flex-2-2
        - Amount of LAR under a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other.
        - The bus work and other substation auxiliary equipment are assumed to remain unaffected, so the Valley Substation spare transformer is assumed to be available to serve load in the Valley South System.

[57] Three SCE AA substations (Vincent, Mira Loma, and El Dorado) have experienced similar events in the past 20 years.

        - The coincident transformer outages are assumed to occur randomly throughout the year and to have a two-week duration – the estimated minimum time to deliver, install, and in-service the remotely-stored spare Valley transformer to restore full transformation capacity to Valley South.
        - Credits the available system tie-line capacity that can be used to reduce EENS.
- Period of Flexibility Deficit (PFD)
    - Maximum number of hours when the available flexibility capacity offered by system tie-lines was less than the required, resulting in LAR.
    - Calculated for N-0 and N-1 contingencies.

6.4. Evaluation of Alternatives Using System Performance Metrics

The alternatives carried forward for quantitative analysis were evaluated using the described system performance metrics and the load forecast described in Section 5. For each metric, the incremental improvement over the baseline No Project Scenario was quantified for each of the project alternatives using the "Effective PV" (mid-range, expected) load forecast. The quantitative evaluation results focus on LAR under N-0 and N-1 contingency conditions and the Flex-1 and Flex-2 metrics. These metrics are most representative of the effective impact on system capacity, reliability and resiliency for each alternative. Other metrics are derived from the calculated LAR values.

The results, compiled in Table 6-1 for the ten -year planning period, present the capacity and reliability/resiliency metrics for the No Project scenario, followed by the equivalent metrics for each of the project alternatives. Where there is a 0, this indicates that the project has completely eliminated the forecasted capacity shortfall (accumulation of LAR under N-0 or N-1 conditions) or reliability/resiliency deficit (accumulation of LAR under the Flex-1, Flex-2-1, or Flex-2-2 scenarios). The results show that none of the project alternatives other than the No Project Scenario result in capacity shortfalls under N-0 contingencies through the 10-year planning period. Additionally, in accordance with SCE Subtransmission Planning Criteria and Guidelines, project scope (impacted line reconductor/rebuild) has been included where necessary for all alternatives to ensure that no LAR is accumulated as a result of N-1 line violations during this period. The ASP provides the greatest overall improvement in both capacity and reliability/resiliency when compared to the No Project scenario. SCE Orange County and SDG&E alternatives also perform well by meeting capacity needs while also providing effective system tie-lines for reliability and resiliency.

Table 6-1 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2028

Alternative	Capacity		Reliability/Resiliency			Capacity Improvement[1]	Reliability/ Resiliency Improvement[1]
	LAR N-0 (MWh)	LAR N-1 (MWh)	Flex-1 (MWh)	Flex-2-1 (MWh)	Flex-2-2 (MWh)		
No Project	250	67	163,415	3,485,449	72,331	-	-
Alberhill System Project	0	0	30,438	39,532	0	100%	98%
SDG&E	0	0	52,762	466,537	16,573	100%	86%
SCE Orange County[3]	0	13	142,815	437,757	13,523	96%	84%
Menifee	0	0	54,051	742,386	21,975	100%	78%
Mira Loma	0	0	99,638	2,283,812	24,608	100%	35%
Valley South to Valley North[2]	0	0	54,051	3,485,449	21,975	100%	4%
Valley South to Valley North to Vista[2]	0	0	54,051	3,485,449	21,975	100%	4%
Centralized BESS in Valley South	0	0	81,951	3,485,449	72,077	100%	2%
Valley South to Valley North and Distributed BESS in Valley South[2]	0	0	44,298	3,485,449	21,975	100%	5%
SDG&E and Centralized BESS in Valley South	0	0	42,455	466,537	16,573	100%	86%
Mira Loma and Centralized BESS in Valley South	0	0	87,130	2,283,812	24,608	100%	36%
Valley South to Valley North and Centralized BESS in Valley South and Valley North[2]	0	0	64,547	3,485,449	21,975	100%	4%
Valley South to Valley North to Vista and Centralized BESS in Valley South[2]	0	0	64,547	3,485,449	21,975	100%	4%

Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of LAR N-0 and LAR N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Note 3: The 13 MWh of LAR N-1 for SCE Orange County is attributed to bus voltage violations.

Table 6-2 shows the results for the year 2048. Like in 2028, and for the same reasons, ASP, SDG&E and SCE Orange County are the strongest performers. Additionally, the ASP shows the best overall improvement across both capacity and reliability/resiliency metrics. The ASP shows minimal LAR under N-0 and N-1 conditions, due entirely to line violations, which are easily corrected through reconductoring when/as necessary.

Table 6-2 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2048

Alternative	Capacity		Reliability/Resiliency			Capacity Improvement[1]	Reliability/ Resiliency Improvement[1]
	LAR N-0 (MWh)	LAR N-1 (MWh)	Flex-1 (MWh)	Flex 2-1 (MWh)	Flex 2-2 (MWh)		
No Project	6,310	2,823	526,314	4,060,195	155,780	-	-
Alberhill System Project	3	202	136,664	87,217	100	99%	95%
SDG&E	244	0	159,201	827,505	51,564	97%	78%
SCE Orange County	232	578	417,292	777,797	44,419	91%	74%
Menifee	114	1,040	163,090	1,207,691	61,787	87%	70%
Mira Loma	1,905	1,151	300,643	2,811,049	68,008	67%	33%
Valley South to Valley North[2]	2,680	1,041	163,090	4,060,195	61,787	59%	10%
Valley South to Valley North to Vista[2]	852	1,041	163,090	4,060,195	61,787	79%	10%
Centralized BESS in Valley South	0	0	248,058	4,060,195	149,603	100%	6%
Valley South to Valley North and Distributed BESS in Valley South[2]	2,564	614	134,586	4,060,195	61,787	65%	10%
SDG&E and Centralized BESS in Valley South	0	0	128,102	827,505	51,564	100%	79%
Mira Loma and Centralized BESS in Valley South	0	15	262,902	2,811,049	67,834	100%	34%
Valley South to Valley North and Centralized BESS in Valley South and Valley North[2]	0	506	194,760	4,060,195	61,697	94%	9%
Valley South to Valley North to Vista and Centralized BESS in Valley South[2]	735	506	194,760	4,060,195	61,697	86%	9%

Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of EENS N-0 and EENS N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Table 6-3 and Table 6-4 demonstrate the longevity of the alternatives from the perspective of meeting N-0 and N-1 planning criteria. These tables identify the year in which N-0 or N-1 violations occur, and identify which line or transformer causes the violation. These planning criteria violations are referred to as capacity shortfalls. Alternatives which first accrue LAR under

N-0 or N-1 conditions after 2028 have no planning criteria violations (and thus do not require system upgrades) within the 10-year planning horizon.

Table 6-3 –Capacity Shortfalls for All Alternatives Through 2048 – N-0 Overloads

Alternative	Year of Overload	Overloaded Element
Alberhill System Project	2046	Alberhill-Fogarty 115 kV Line
SDG&E	2040	**Valley South Transformer**
SCE Orange County	2040	**Valley South Transformer**
Menifee	2043	**Valley South Transformer**
Mira Loma	2031	**Valley South Transformer**
Valley South to Valley North	VN: 2037 VS: 2043	**Valley North Transformer** **Valley South Transformer**
Valley South to Valley North to Vista	VN: 2041 VS: 2043	**Valley North Transformer** **Valley South Transformer**
Centralized BESS in Valley South	None	None
Valley South to Valley North and Distributed BESS in Valley South	VN: 2037	**Valley North Transformer**
SDG&E and Centralized BESS in Valley South	None	None
Mira Loma and Centralized BESS in Valley South	None	None
Valley South to Valley North and Centralized BESS in Valley South and Valley North	None	None
Valley South to Valley North to Vista and Centralized BESS in Valley South	VN: 2041 VS: None	**Valley North Transformer** None
Note: Bolded entries represent capacity shortfalls at the Valley Substation level.		

Table 6-3 demonstrates that all alternatives meet the N-0 planning criteria for the 10-year planning horizon (2028), but some incur N-0 overloads (both line and transformer) well within the 30-year horizon used in the analysis. In practice, these overloads would need to be corrected by SCE through implementation of future projects. For the purpose of this Planning Study, the impacts of these shortfalls are reflected in reduced benefits for the project (or by pairing the alternative with energy storage to create a hybrid alternative).

Table 6-4 –Capacity Shortfalls for All Alternatives – N-1 Overloads

Alternative	First Overload Year[1]	First Overloaded Element	Total Number of Lines Experiencing Criteria Violations (through 2048)
Alberhill System Project	2038	Alberhill-Fogarty 115 kV Line	3
SDG&E	None	None	None
SCE Orange County	2033	Moraga-Pechanga 115 kV Line	4
Menifee	2033	Moraga-Pechanga 115 kV Line	6
Mira Loma	2032	Valley-Newcomb Skylark 115 kV Line	10
Valley South to Valley North	2033	Moraga-Pechanga 115 kV Line	6
Valley South to Valley North to Vista	2033	Moraga-Pechanga 115 kV Line	6
Centralized BESS in Valley South	None	None	None
Valley South to Valley North and Distributed BESS in Valley South	2033	Moraga-Pechanga 115 kV Line	5
SDG&E and Centralized BESS in Valley South	None	None	None
Mira Loma and Centralized BESS in Valley South	2048	Valley-Newcomb-Skylark 115 kV Line	1
Valley South to Valley North and Centralized BESS in Valley South and Valley North	2033	Moraga-Pechanga 115 kV Line	5
Valley South to Valley North to Vista and Centralized BESS in Valley South	2033	Moraga-Pechanga 115 kV Line	5

Note 1: This is the year in which the first line is overloaded during an N-1 condition. For many alternatives, there are additional lines which are overloaded at later dates and contribute to the N-1 LAR value provided in Table 6-2.

Table 6-4 demonstrates that all alternatives meet the N-1 planning criteria for the 10-year planning horizon (2028). However, the majority of alternatives incur N-1 planning criteria violations well before 2048. As in the case of N-0 violations discussed above, SCE would be required to correct these violations through implementation of future projects (typically reconductoring for line violations). For the purpose of this Planning Study, the impact of these violations is reflected in reduced benefits as opposed to individually estimating the cost of mitigation for each violation.[58] The costs and complexity of the individual mitigations are typically not large, nor are the reduced

[58] While individually the scope of these projects to address N-1 line violations is not large, it was not practical in the current study to develop scope and estimates for the large number of line violations across multiple alternatives. The specific projects would typically include reconductoring to address the specific line violations and potentially modification or replacement of structures to accommodate the higher conductor loads.

benefits particularly large when discounted to reflect that they occur later in the time horizon addressed by the analysis. However, the timing and number of line violations and the associated LAR reflecting these 115 kV line violations (shown in Table 6-1 and 6-2) that occur beyond the ten-year planning horizon are both indicative of the relative robustness of each project solution in meeting both near-term and long-term capacity needs.

7.0 Siting and Routing

A siting and routing study was performed on the set of alternatives which were carried forward for quantitative analysis. The siting and routing study identified preferred substation sites and line routes, which were used to assess risk, understand potential environmental impacts, and estimate associated costs for each of the project alternatives. This section describes the approach and methodology used to perform the siting and routing study.

7.1. Opportunities, Concerns, and Constraints Evaluation

Each project alternative requires at least one scope element (e.g., substation, transmission or subtransmission line construction, or energy storage site), with some alternatives sharing scope elements (i.e., the Hybrid Alternatives). For each unique scope element, a discrete study area was created, which defined the geographic area for which the siting and routing study would be performed.

Within each study area, an Opportunities, Concerns, and Constraints (OCC) evaluation was performed by Insignia Environmental[59] in collaboration with SCE to assist in developing initial sites (locations for substations and/or BESS) and route segments (locations for transmission and subtransmission lines):

Opportunity: An opportunity is an area that would provide an advantage to construction and/or operation of the project. Examples are:

- Existing SCE right-of-way
- SCE-owned property
- Previously graded parcels
- Vacant parcels
- Industrial land-use designations

Concern: A concern is an area that could potentially pose a disadvantage to construction and/or operation of the project. Examples are:

- Undisturbed land
- Residential neighborhoods
- Schools
- Tribal land

Constraint: A constraint is an area that should be avoided if at all possible. Examples are:

- Federal property

[59] Insignia Environmental was contracted by SCE to develop the framework for the OCC evaluation in a web-based GIS mapping tool. Insignia's scope of work included developing initial sites and routes for each alternative, facilitating scoring of sites and routes by SCE SMEs, and performing environmental cost estimating services for preferred sites and routes.

- Areas prone to landslide
- Habitat Conservation Plan Areas
- Areas with sensitive habitats
- Selected airport land-use zones
- Irregular parcel shapes

A geospatial information system (GIS) database was utilized to define opportunities, concerns, and constraints within each study area. Potential sites and route segments were identified within each corresponding study area using an approach that attempted to maximize opportunities while minimizing concerns and constraints. These sites and route segments were added to the GIS database. Initial sites and route segments for each alternative are provided in Appendix C of this Planning Study.

7.2. Scoring of Sites and Segments

SCE Subject Matter Experts (SME) reviewed the GIS database to score the initial sites and route segments using defined siting and routing factors, which are provided in Table 7-1.

Table 7-1 – Siting and Routing Factors

Siting Factors	**Routing Factors**
Civil Engineering	Civil Engineering – Access Roads
Community	Community
Electrical Needs – Distribution	Constructability – Transmission Project Delivery
Information Technology Telecommunications	Electrical Needs – Field Engineering
Land Use	Information Technology Telecommunications
Transmission	Subtransmission / Transmission Design Management
Transmission Telecommunications	
Subtransmission	

Each siting and routing factor contains multiple categories, such as removal of existing structures, permits and restrictions, terrain, accessibility, etc. which are scored based on the SME's review.

The scoring process resulted in a preferred site or preferred route segment for each study area, which were combined as necessary to define each project alternative. The preferred sites and route segments for each alternative are provided in Appendix C of this Planning Study.

8.0 Cost-Benefit Analysis

The project alternatives were evaluated from a cost-benefit standpoint by developing lifecycle costs and monetizing the system performance metrics of each alternative. The project alternatives were then ranked as a function of the benefit-to-cost ratio. The details of the cost-benefit analysis can be found in Quanta Technology Report *Benefit Cost Analysis of Alternatives*.

Note that the cost-benefit analysis differs from a conventional return on investment analysis in that the benefits do not reflect revenues incurred as a result of the investment, but rather they are treated as relative estimates of avoided costs that would be incurred by SCE customers if the investments were not made. Care was taken to apply a consistent approach across alternatives in terms of development of costs as well as in the approach for determination and monetization of the benefits (avoided customer costs). Accordingly, more attention should be paid to the relative performance of alternatives than to the absolute values of accrued benefits and associated benefit-to-cost ratios.

8.1. Methodology

8.1.1. Costs

The lifecycle costs of each project alternative were calculated, including upfront and future capital costs, as well as recurring operations and maintenance (O&M) costs. Project costs were spread out across likely project implementation (design, procurement and construction) durations, ranging from 2 to 5 years, depending on project scope and complexity. These costs were then discounted to the present using the PVRR[60] method consistent with SCE practice when determining total present-value cost for capital projects.

The cost estimating approach used for each project element is summarized in Table 8-1.

[60] PVRR is a single calculated value that sums the time-discounted cash flows of the project (in terms of revenue requirements) for each year of the project.

Table 8-1 – Cost Estimating Approach Summary

Project Element	Estimate Approach
Licensing	• Past ASP licensing costs applied to all projects, with additional costs accruing at the same rate as ASP for an additional 2 years for ASP and 4 years for other alternatives to account for CEQA activities.
Substation	• Developed engineering scoping checklists to identify major scope elements (switchracks, transformers, circuit breakers, disconnect switches, foundations, civil work, etc.). • SCE cost estimating SMEs created cost estimates based on scoping checklists.
Corporate Security	• Based on past SCE projects of similar scope.
Bulk Transmission and Subtransmission	• Identified length of routes, line type (single-circuit, double-circuit, overhead, underground) and terrain. • Applied a combination of CAISO and SCE Unit Costs.
Transmission Telecommunications	• Identified length of fiber optic line based on preferred routes. • Applied a combination of CAISO and SCE Unit Costs.
Distribution	• Review of impact to existing distribution circuits along preferred routes to identify likely scope. • Applied SCE Unit Costs based on recent project bids.
IT Telecom	• Included for Substation and BESS sites, and alternatives with line protection upgrades. • Applied a combination of CAISO and SCE Unit Costs.
Real Properties	• Bottom-up cost estimate utilizing siting and routing information to identify required parcels and ROWs.
Environmental[61]	• Bottom-up cost estimate incorporating local planning and permit development and execution (surveying, mitigation, monitoring) support.
BESS	• Based on industry data to include inverter, battery, balance of plant and contractor turnkey costs. • Sized to meet N-0 transformer capacity shortfalls for 30 years. • Sizes are augmented to account for degradation
Owner's Agent	• 10% of above costs for owner's agent costs.
Uncertainty	• Scored impact and probability of various uncertainty categories using 3x3 matrix (low, medium, high). See Appendix D for uncertainty scoring matrix.

The siting and routing study was heavily relied upon to inform cost estimates for each alternative, since a significant portion of project costs rely on the specific substation/BESS site locations and the routes for subtransmission and transmission lines to implement the alternatives. For line construction, cost per mile was estimated by considering the number of poles per mile and the amount of conductor/cable per mile, while incorporating the potential topology, climate, and population density for the line route into the construction cost estimate. For new substations and additions to existing substations, costs were estimated using known costs of substation equipment while also incorporating earthwork and new construction costs. As described in Table 8-1, real properties costs were accounted for as necessary for all alternatives using preferred siting and routing information. O&M costs for non-BESS project scope were set at 1.5% of capital

[61] Environmental cost estimating was performed by Insignia Environmental.

expenditures for equipment related costs (i.e., substation, transmission, subtransmission, etc.), escalated at 2.5% each year based on industry experience.

For alternatives that included BESS, both centralized and distributed, costs were estimated using typical $/kWh and $/kW system costs for the base system purchase. O&M costs were estimated by considering a 1.3% and 1.7% ongoing expenditure, using the total kW-cost and kWh-cost of the system, respectively, as the basis.[62] For all BESS alternatives, batteries are assumed to be installed incrementally, rather than all at once, the price of which is discounted over time according to an assumed cost-change factor. The total cost of the system includes periodic augmentation of installed batteries, to account for capacity degradation, as the age of each installed BESS nears end of life[63], as well as inverter replacements every 10 years.

Electricity wholesale market revenue was considered by allowing the BESS to participate in capacity or regulation markets, except during the months of June, July, August, and September, when electrical load in the region is projected to be highest. The time of year was restricted to ensure required availability of the BESS for the reliability function – the BESS must be available to serve peak load at various times throughout the year. Revenue from market participation activities was accounted for on a yearly basis and discounted back to the present using a 10% discount factor. The present value of market revenue was then used to offset the total project cost.

Uncertainty costs were also incorporated into the cost estimate to account for the relative complexity and extent of detailed project development, environmental analysis and design for each alternative. Uncertainty costs are intended to reflect costs comprising a combination of risk and contingency.

A matrix consisting of various general, transmission, subtransmission, substation and battery project uncertainties was developed in order to quantify challenges typically encountered during project planning and execution which add delay and costs, such as public opposition, permitting or agency delay, and required undergrounding. The preferred sites and routes of each alternative were reviewed by SCE subject matter experts to determine the extent that the uncertainty categories would apply. A total uncertainty score based on the likelihood and impact of each uncertainty category was developed for each alternative and the ASP, which served as a basis because of the maturity of its environmental, licensing, and engineering design relative to the other alternatives.

The uncertainty score of each alternative was translated to an uncertainty cost as a percentage of total project costs. The lower bound of the uncertainty costs was based on the ASP uncertainty score and ratio of the known ASP risk and contingency costs, and the upper bound of the uncertainty costs was capped at 50%, which is consistent with AACE Level 3/4 cost estimate accuracy, so as to limit the impact of risk/uncertainty on the cost-benefit analysis results. However, SCE's experience is that project costs for projects that have not been through the complete process of development, design, licensing and stakeholder engagement can change by more than 50%

[62] For BESS cost-estimates, several publically available sources of BESS cost information were consulted, including sources from Lazard, Greentech Media, and Pacific Northwest National Laboratory.
[63] See Balducci, et al, PNNL-28866, "Energy Storage Technology and Cost Characterization Report", July 2019.

when advancing to the execution stage. The risks of higher costs due to these various sources of uncertainty are therefore addressed on a qualitative basis in Section 9.0.

Uncertainty scores and costs, as a percentage of total capital expenditures, are provided for each alternative in Table 8-2. Generally the highest uncertainty scores are associated with projects with the longest or most challenging line routes. Additionally, projects that have a combination of lines, substations and BESS sites, and thus include risks associated with each project element, have uncertainty scores approaching the higher end of the range. While overall the BESS project element has lower uncertainty contribution than substations or lines, the Valley South to Valley North and Distributed BESS in Valley South alternative has lower uncertainty than the Centralized BESS alternatives because it is assumed that development inside existing SCE distribution substation fence lines has less overall licensing, siting and execution risk than developing a new larger centralized BESS site. Complete scoring details are provided in Appendix D.

Table 8-2 – Uncertainty Scores and Costs for All Alternatives

Alternative	Uncertainty Score	Uncertainty Costs (% of Capital Expenditures)
Alberhill System Project	153	26%
SDG&E	287	48%
SCE Orange County	275	46%
Menifee	244	41%
Mira Loma	264	44%
Valley South to Valley North	188	32%
Valley South to Valley North to Vista	198	33%
Centralized BESS in Valley South	181	31%
Valley South to Valley North and Distributed BESS in Valley South	177	30%
SDG&E and Centralized BESS in Valley South	300	50%
Mira Loma and Centralized BESS in Valley South	277	46%
Valley South to Valley North and Centralized BESS in Valley South and Valley North	249	42%
Valley South to Valley North to Vista and Centralized BESS in Valley South	265	44%

Table 8-3 shows the cost estimates for all alternatives. The alternatives are ranked in terms of PVRR, and the total cost in nominal dollars is included for context. The alternatives that merely transfer load from one system to another are the lowest in total cost, while the Conventional and Hybrid Alternatives that require new substation construction rank highest. Alternatives incorporating BESS become particularly expensive when the BESS is required to meet longer duration capacity shortfalls, thus requiring large scale battery additions.

Table 8-3 – Costs, Ranked Lowest to Highest by PVRR for All Alternatives

Alternative	Total Nominal Capital Cost ($M)	PVRR ($M)
Valley South to Valley North	$221	$207
Valley South to Valley North and Distributed BESS in Valley South	$326	$232
Valley South to Valley North to Vista and Centralized BESS in Valley South	$505	$289
Valley South to Valley North to Vista	$317	$290
Mira Loma	$365	$309
Menifee	$396	$331
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$1,172	$367
SDG&E	$540	$453
Alberhill System Project	$545	$474
Centralized BESS in Valley South	$1,474	$525
SDG&E and Centralized BESS in Valley South	$923	$531
Mira Loma and Centralized BESS in Valley South	$1,396	$560
SCE Orange County	$951	$748

8.1.2. Benefits

Four main LAR benefit categories were selected for monetization: LAR under N-0 conditions; LAR under N-1 conditions; Flex-1; and Flex-2.[64] These metrics most accurately reflect the reliability and resiliency benefit of the alternatives to SCE customers, most readily differentiate among the alternatives, and are not duplicative of each other and thus can be combined to reflect the overall benefit of alternatives. Additionally, the analysis monetized the reduction in System Losses achieved by each alternative, although this metric was not a significant differentiator among alternatives in the cost-benefit analysis.

In monetizing these benefits, the metrics are first adjusted by assigning probabilities for the line or transformer outages that are associated with each metric. Line outage probabilities were calculated from historical data (2005 – 2018) for the Valley North and South Systems in order to have a large enough sample of outages to support the statistical analysis. Outage probabilities were calculated for single contingency (N-1) events to monetize the LAR (N-1) metric and for double-circuit contingency (N-2) events for the Flex-1 metric. The aggregate line outage probability for the entire Valley System is then applied to each line or combination of lines in Valley South on a per line-mile basis. N-1-1 outages were not included in the Flex-1 monetization because the probability of independent, coincidental outages occurring during system load conditions in which loss of service to customers would occur is extremely low relative to N-1 contingencies. Note that this simplification somewhat understates the value of system tie-lines. System tie-lines are

[64] The analysis also includes system losses as a monetized benefit metric. They are not a focus of the alternatives analysis in either the quantitative metrics assessment or the cost-benefit analysis, as a reduction in losses typically represents a small fraction of the overall benefits that a project provides.

commonly used to either proactively or reactively limit the impact of potential N-1-1 outages that might otherwise occur when lines are out of service for extended periods of time for planned maintenance or construction. In cases where tie-lines are not available, where practical, these construction or maintenance activities will be limited to times of the year when system loading conditions will not result in loss of service to customers should an additional (unplanned) line outage occur at the same time as the planned outage. The value of this flexibility is not captured in this analysis. Based on the historical Valley South and Valley North outage data, the mean line outage durations were calculated to be 2.8 hours (LAR N-1) and 3.0 hours (Flex-1).

Transformer outage probabilities were based on a postulated 1-in-100 year event for Flex-2-1 and based on an industry survey and statistical analysis of major (greater than 7 day) transformer failures for Flex-2-2[65]. The Flex-2-2 scenario assumes that one of the two normally load-serving transformers of the Valley South System experiences a catastrophic fire or explosion that causes collateral damage to the adjacent transformer. The spare transformer, which is not located within the immediate vicinity of the two load-serving transformers, is unaffected and is assumed to be aligned to the undamaged, Valley South 115 kV bus.

Transformer outages associated with both the Flex-2-1 and Flex-2-2 metrics were assumed to be two weeks, which is representative of the minimum restoration time for a high impact low probability (HILP) event resulting in a complete loss of Valley Substation. This assumption likely understates the likely duration of a Flex-2 type event considering that similar events at SCE have taken months to repair as a result of the collateral damage to structures, bus work, control cables and other auxiliaries. This, most-optimistic, duration was assumed so that a singular metric would not dominate the cost benefit analysis results

These probability adjusted metrics were then monetized using cost of service interruption data from the SCE Value of Service study (as presented in the SCE General Rate Case[66]). The primary objective of the Value of Service study is to estimate outage costs for various customer classes, using the well-established theoretical concept of "value-based reliability planning." This concept has been used in the utility industry for the past 30 years to measure the economic value of service reliability. The estimation of outage costs differs for customer classes: commercial outage costs are based on a direct-cost measurement, since these costs are easily measured, whereas residential outage costs are based on a willingness-to-pay survey (customer perception or estimation of costs rather than a detailed buildup). The study presents equivalent costs of unserved demand (kW) and load (kWh) from the perspective of commercial and residential customers. As discussed earlier, the absolute value of the cost of service interruption is not critical as the same values are applied to all alternatives.

Figure 8-1, which is derived from the SCE Value of Service (VoS) study, provides the cost of unserved load for outages of various durations. This figure shows that the initial hour of

[65] See CIGRE Reference 642, Transformer Reliability Survey, December 2015.

[66] See WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A – pp. 12 – 109 – Southern California Edison: 2019 Value of Service Study.

interruption is deemed most costly on a $/kWh basis for both customer classes declining through the 4th hour then stabilizing.

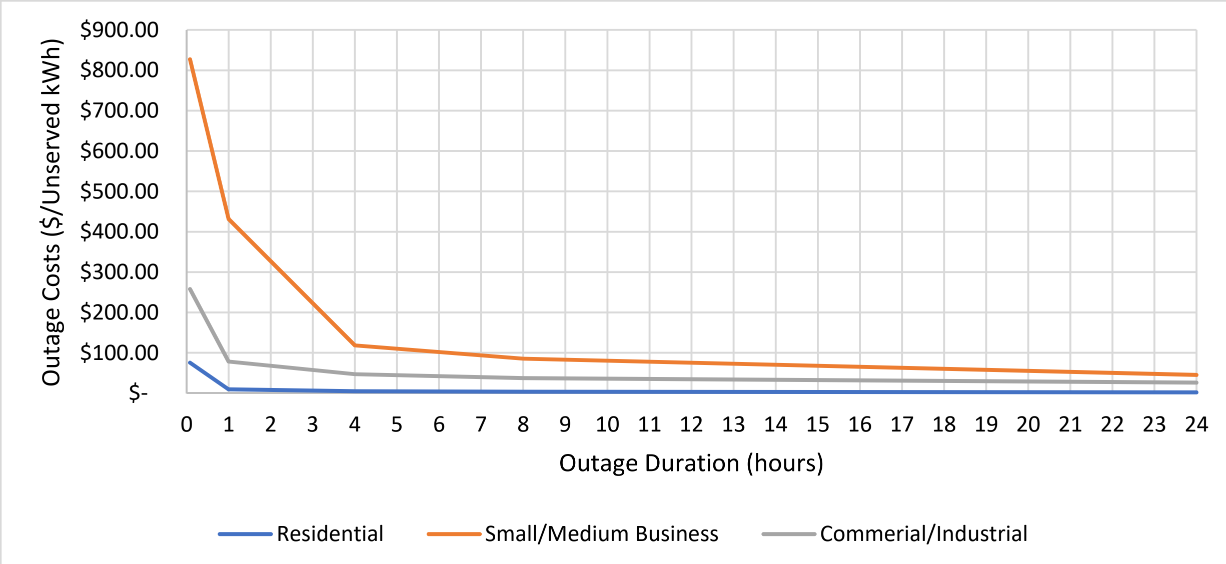

Figure 8-1 – Customer Outage Costs

It is SCE's practice to minimize the impact of an extended outage to any single customer by periodically rolling the outages within the system. Accordingly, in applying the VoS study to the LAR (N-0), LAR (N-1), Flex-1 and Flex-2-2 metrics, the one hour outage monetization rate in the VoS study is applied for each hour of the period where load would be unserved. For the Flex 2-1 metrics the average of the one hour and 24 hour monetization rates is used because in that associated outage scenario load cannot be rolled. The average of the two rates is applied to recognize that outages lasting substantially longer than 24 hours have impacts not reflected in the VoS study 24 hour rate, such as property damage, relocation, and other direct costs. Based on data reported in the VoS study, a mix of 33% residential, 36% small/medium business and 31% commercial and industrial customer load was used to monetize the annual, probability-weighted LAR values for each of the metrics (1 hour costs for LAR N-0, LAR N-1, Flex-1 and Flex-2-2, average of 1 hour and 24 hour costs for Flex-2-2). The customer class load percentages and costs per kWh are provided in Table 8-4.

Table 8-4 –Value of Service by Customer Class

Customer Class	**Load %**	**$/kWh (1 hour)**	**$/kWh (Flex-2-1)**
Residential	33%	$9.47	$5.68
Small/Medium Business	36%	$431.60	$238.41
Commercial & Industrial	31%	$78.28	$52.11

Table 8-5 ranks the total monetized project benefits for each project from highest to lowest. As was the case for the benefits (before monetization) described above, the alternatives that directly address the capacity need through the construction of adequate substation transformation capacity, such as the ASP, SDG&E, and SCE Orange County alternatives, and directly address the reliability/resiliency need through the creation of system tie-lines provide the greatest overall monetized benefits. These alternatives provide a means to initially transfer a large amount of load away from the Valley South System, thus increasing the operating margin of the Valley South System transformers and extending the timeline for when the transformers would again be at risk of becoming overloaded. In addition, the effectiveness of the system tie-lines created in these alternatives is maximized, since the new substations (with substantial transformation capacity) do not constrain the amount of additional load that can be transferred during planned or unplanned contingencies. Among these alternatives, the ASP would provide the greatest benefits, largely because of its location from the perspective of electrical system performance, and maximizes the effectiveness of system tie-lines.

Like the ASP alternative, the Menifee alternative creates a new 500 kV to 115 kV bulk power system supplied substation and thus is robust in meeting capacity needs. However, it is not as effective in addressing reliability and resiliency contingency events. This is because the system tie-lines created by this alternative do not allow for the additional transferring of load from the Valley South System to the Valley North System. The tie-lines do allow for transfer of load back to Valley South from the new Menifee system if there were to be a reliability/resiliency need in that system; thus the tie-lines do benefit the relatively small number of customers that were initially transferred to the new Menifee system.

Hybrid alternatives that use BESS to address long-term capacity shortfalls, along with system tie-lines, provide a higher level of overall benefits relative to the associated baseline, conventional scope (e.g., the SDG&E and Centralized BESS in Valley South alternative accrues higher benefits than SDG&E, due to the improved performance of the LAR N-0 metric, while alternatives that transfer load from one existing system to another, such as the Valley South to Valley North and Valley South to Valley North to Vista alternatives, provide the least overall benefit among the alternatives. These load-transfer alternatives actually perform well in improving short-term capacity, but do not significantly improve reliability/resiliency between the systems (through construction of new subtransmission lines to transfer load away from the Valley South System) on a permanent basis, as opposed to the intended, temporary use of system tie-line capacity for operational flexibility. In these cases, no additional load can be transferred during planned or unplanned contingencies in Valley South; however, load can be transferred back to Valley South from Valley North if there is a problem in the Valley North system. This transfer capability is of limited value to the Valley North system because Valley North already has multiple effective system tie-lines.

Centralized BESS ranks at the lower tier of alternatives despite satisfying the transformation capacity need and addressing additional line violations over the 30 -year analysis period. However, the Centralized BESS alternative realizes only a very small amount of the reliability/resiliency benefits because it does not include system tie -lines which are needed to address longer duration events such as a catastrophic failure affecting multiple transformers at Valley and to address line outages that can be localized and also have extended duration.

Table 8-5 – Monetized Benefits, Ranked Highest to Lowest for All Alternatives

Alternative	Benefit($M)
Alberhill System Project	$4,282
SDG&E and Centralized BESS in Valley South	$4,041
SCE Orange County	$4,021
SDG&E	$4,001
Menifee	$3,882
Mira Loma and Centralized BESS in Valley South	$3,132
Mira Loma	$2,601
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$2,542
Centralized BESS in Valley South	$2,535
Valley South to Valley North to Vista and Centralized BESS in Valley South	$2,479
Valley South to Valley North to Vista	$2,470
Valley South to Valley North and Distributed BESS in Valley South	$2,165
Valley South to Valley North	$2,156

8.1.3. Load Forecast Uncertainty

As discussed in Section 5.4, uncertainty in the 30 -year load forecast was evaluated by considering three distinct approaches for incorporating DER growth. These forecasts were then used to perform cost-benefit sensitivity analyses for all the alternatives. The methodology for determining the costs and benefits for these cost-benefit sensitivity analyses is identical to the methodology just described.

8.2. Results

8.2.1. Cost-Benefit Analysis - Ratio

Table 8-6 shows the results of comparing benefits to costs for all of the project alternatives, grouped by the alternatives that meet project objectives and those that do not. The benefit-cost ratio computes the monetized benefits discounted to the present divided by the PVRR costs.

Table 8-6 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$4,282	9.0	Yes
SDG&E	$453	$4,001	8.8	Yes
Mira Loma	$309	$2,601	8.4	Yes
SDG&E and Centralized BESS in Valley South	$531	$4,041	7.6	Yes
Mira Loma and Centralized BESS in Valley South	$560	$3,132	5.6	Yes
SCE Orange County	$748	$4,021	5.4	Yes
Menifee	$331	$3,882	11.7	No
Valley South to Valley North	$207	$2,156	10.4	No
Valley South to Valley North and Distributed BESS in Valley South	$232	$2,165	9.3	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	$2,479	8.6	No
Valley South to Valley North to Vista	$290	$2,470	8.5	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	$2,542	6.9	No
Centralized BESS in Valley South	$525	$2,535	4.8	No

The performance of the three alternatives that perform best in the overall cost-benefit analysis (Menifee, Valley South and Valley North, and Valley South to Valley North and Distributed BESS in Valley South) is driven principally by their lower cost. These alternatives however do not meet the project objective of having system tie-lines that are effective in transferring additional load out of Valley South in the event of line or transformer outages in the Valley South System that result in a need for this flexibility to be able to serve load. In all of these alternatives, the system tie-lines that are created allow a limited transfer of load back into Valley South from the adjacent (Menifee or Valley North) system. This capability benefits the relatively small number of customers that are served by the substations transferred out of Valley South in implementing the project alternative but the customers remaining in the Valley South System continue to have no useful system tie-lines to address their reliability/resiliency needs. Creating effective system tie-lines for these alternatives is not practical because additional distribution substations would need to be transferred to make the system tie-lines effective. Distribution substations nearest Valley Substation (and thus sufficiently accessible to be included in the alternative) are also substations through which power coming from the Valley South System transformers is routed before continuing on a path to serve the remaining distribution substations to the south. Transferring these substations, without significant additional 115 kV subtransmission line construction to effectively bypass them, would disrupt the design of the electrical network and adversely impact the ability to serve the more distant substations in the Valley South System.

Among the alternatives that meet project objectives, ASP, SDG&E, and Mira Loma are included in the top tier of alternatives, with ASP ranking highest. Both ASP and SDG&E rank high primarily due to their high benefits. These alternatives provide long-term N-0 transformer capacity margin and have effective system tie-lines. The SDG&E alternative satisfies the capacity need through 2040 while ASP meets the need beyond 2048. The benefit-to-cost ratio of the Mira Loma alternative is similar to SDG&E and ASP; however, in this case the cost/benefit performance is driven by low costs and moderate benefit levels. The Mira Loma alternative is a short term capacity solution, as it does not meet capacity needs beyond 2031 as a standalone alternative. This is the shortest term capacity solution among of all the alternatives. In as soon as 2031, another project or NWA solution would need to be implemented to address the transformer capacity N-0 contingency violations associated with this shortfall. These incremental capacity additions are reflected in the Mira Loma and Centralized BESS in Valley South Alternative and result in an alternative that is ranked much lower in the overall benefit-to-cost ratio (number 5 of 6 for alternatives that meet project objectives and among the lowest overall).

8.2.2. Cost-Benefit Analysis - Incremental

When there are large differences in costs and benefits among alternatives, as in the analysis reported here, it is appropriate to consider the incremental benefit that is obtained for an increased investment relative to a lower cost alternative. This approach formalizes and quantifies the decisions made every day by consumers when they decide whether buying a higher priced product that comes with additional benefits is "worth it". The approach used for this incremental cost - benefit analysis is described below.

The incremental cost-benefit analysis ranks the projects from lowest to highest in PVRR cost. The analysis begins by considering the lowest cost project and comparing the benefits of the project to the cost of the project. If the benefits are greater than the costs, that is, the benefits outweigh the costs, then the project is deemed viable and chosen as the baseline. The next highest-cost project is then considered. The incremental benefits of the second project are compared to the incremental, or additional, cost of the second project. If the incremental benefits of the second project are greater than the incremental cost of the second project, this second project is deemed viable and becomes the new baseline.

It is possible that the next highest-cost project in the list provides fewer benefits than the previous baseline project. The incremental benefits would be negative, i.e., the project under consideration provides even fewer overall benefits than the current baseline project. In this case, the benefit-to-cost ratio is negative, and the project is not deemed viable. Similarly, a project may provide positive incremental benefits, but the incremental cost of the project may be greater than the incremental benefits provided. In this case, the benefit-to-cost ratio is <1, and the project is not deemed viable. In either of these cases, the project under consideration is rejected, and the next highest-cost project in the list is considered. This process is repeated, moving though the list in order of lowest to highest cost, until no other alternative can provide incremental benefits that exceed the incremental cost. Table 8-7 shows the results of the incremental cost-benefit analysis.

Table 8-7 – Incremental Cost-Benefit Analysis Results for All Alternatives

Alternative	PVRR Cost ($M)	Cost Ranking (least to greatest)	Cost Ranking Comparison	Δ Benefits / Δ Costs	Incremental Benefits > Costs?
Valley South to Valley North	$207	1	-	-	-
Valley South to Valley North and Distributed BESS in Valley South	$232	2	1 vs 2	0.36	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	3	1 vs 3	3.9	Yes
Valley South to Valley North to Vista	$290	4	3 vs 4	-9.0	No
Mira Loma	$309	5	3 vs 5	6.1	Yes
Menifee	$331	6	5 vs 6	58.2	Yes
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	7	6 vs 7	-37.2	No
SDG&E	$453	8	6 vs 8	0.98	No
Alberhill System Project	$474	9	6 vs 9	2.8	Yes
Centralized BESS in Valley South	$525	10	9 vs 10	-34.3	No
SDG&E and Centralized BESS in Valley South	$531	11	9 vs 11	-4.2	No
Mira Loma and Centralized BESS in Valley South	$560	12	9 vs 12	-13.4	No
SCE Orange County	$748	13	9 vs 13	-1.0	No

The analysis begins with the lowest cost project, Valley South to Valley North. Moving through the list from lowest to highest cost (identified in the column titled Cost Ranking with 1 being least cost and 13 being greatest cost), the next project is Valley South to Valley North with Distributed BESS in Valley South. The incremental benefits in moving from Valley South to Valley North, to Valley South to Valley North and Distributed BESS in Valley South do not exceed the incremental costs; as such, the Valley South to Valley North alternative remains the baseline alternative for the next highest cost alternative. This process is repeated until the final alternative which provides an incremental benefit-to-cost ratio greater than 1 is identified. The ASP provides substantial incremental benefits over the incremental cost (2.8) compared to Menifee. Thus, the results show that the higher benefits of ASP are cost effective.

8.3. Load Forecast Uncertainty

SCE recognizes there is additional potential option value in alternatives with less expensive upfront costs that meet system needs for a shorter timeframe over alternatives with higher upfront costs but longer -term system benefits. Specifically, should load develop slower than forecasted, the alternatives with lower front -end costs would incur future costs later than currently modeled, thus favorably affecting their cost-benefit performance. An analysis was performed to evaluate the sensitivity of the cost-benefit analysis results to uncertainty in the 30-year load forecast.

8.3.1. Spatial Load Forecast – Lower

Table 8-8 shows the results of comparing costs to benefits for all project alternatives, given the lower (Spatial PVWatts) forecast. As discussed in Section 5.4, the Spatial PVWatts forecast represents a lower load forecast reflecting higher rates of on-peak PV or other load reducing DERs. It represents a nominal average annual load growth rate of 0.6% compared to the 0.8% rate reflected in the base (Dependable PV) forecast. Due to the lower forecasted load, fewer benefits are accrued for all the alternatives, thus lowering the benefit/cost ratios. Costs for all alternatives that include BESS are also reduced due to the reduced quantity of batteries required to meet system N-0 capacity needs, resulting in the benefit-to-cost ratios of the alternatives being more closely grouped. However, the reduced load forecast does not significantly affect the relative performance of the highest ranked alternatives. The highest ranked alternatives are still Menifee, ASP, SDG&E, and SDG&E and Centralized BESS in Valley South. The relative performance of the Mira Loma alternative does drop somewhat due to the reduced value of meeting capacity needs relative to the Flex 2-1 metric in the low load forecast scenario. The ASP continues to have the best incremental cost benefit analysis performance with an incremental benefit to cost ratio of 10.5 relative to the next best performing alternative (SDG&E).

Table 8-8 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Lower Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$2,740	5.78	Yes
SDG&E	$453	$2,520	5.56	Yes
SDG&E and Centralized BESS in Valley South	$479	$2,520	5.26	Yes
Mira Loma	$309	$1,512	4.89	Yes
Mira Loma and Centralized BESS in Valley South	$448	$1,625	3.63	Yes
SCE Orange County	$748	$2,533	3.39	Yes
Menifee	$331	$2,381	7.19	No
Valley South to Valley North and Distributed BESS in Valley South	$200	$955	4.77	No
Valley South to Valley North	$207	$955	4.61	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$255	$1,039	4.08	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$269	$1,036	3.85	No
Valley South to Valley North to Vista	$290	$1,036	3.57	No
Centralized BESS in Valley South	$381	$1,032	2.71	No

8.3.2. Spatial Load Forecast – Higher

Table 8-9 shows the results of comparing costs to benefits for all project alternatives, given the higher (Spatial Base) forecast. The Spatial Base forecast assumes continuation of current trends in PV and other DER adoption and thus is reflective of a future scenario where increased electrification effectively offsets increases in DER adoption. The result is an average annual load growth rate of 1.0% compared to 0.8% in the base (Spatial Effective PV) forecast.

The relative performance of alternatives with capacity margin improves in this scenario and additional reliability/resiliency benefits also accrue due to the increasing load at risk. The overall benefits and benefit-to-cost ratios increase substantially overall, but the overall benefit-to-cost ratio rankings of alternatives does not substantially change. The incremental benefit-to-cost ratio advantage of ASP increases substantially relative to Menifee (the second best performing alternative), with an incremental benefit-to-cost ratio of 4.1. This is because the ASP has substantial capacity margin to address higher load growth and the reliability/resiliency benefits associated with its system tie lines are amplified due to the increased load at risk. The relative performance of alternatives with heavy reliance on BESS is adversely affected under this scenario due to increasing battery costs.

Table 8-9 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Higher Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$7,788	16.4	Yes
SDG&E	$453	$7,218	15.9	Yes
Mira Loma	$309	$4,766	15.4	Yes
SDG&E and Centralized BESS in Valley South	$658	$7,523	11.4	Yes
Mira Loma and Centralized BESS in Valley South	$601	$6,604	11.0	Yes
SCE Orange County	$748	$7,258	9.7	Yes
Menifee	$331	$7,201	21.8	No
Valley South to Valley North to Vista	$290	$4,617	15.9	No
Valley South to Valley North	$207	$2,618	12.7	No
Valley South to Valley North and Distributed BESS in Valley South	$228	$2,736	12.0	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$404	$4,771	11.8	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$700	$6,016	8.6	No
Centralized BESS in Valley South	$848	$6,008	7.1	No

8.4. Battery Cost Sensitivity

Cost estimates for BESS are based on current industry data and include battery, inverter, balance of plant, and engineering, procurement, and construction costs, and reflect future price reductions anticipated by industry analysts. The lower upfront-cost alternatives with BESS could potentially benefit from lower -than -expected future costs through improvements in technology or market conditions. A sensitivity analysis was performed with BESS costs reduced by 50% to quantify this scenario.

Table 8-10 shows the results of the benefit-to-cost comparison for the lower (Spatial PVWatts) forecast. The alternatives with BESS are shown in red for emphasis.

Table 8-10 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Reduced Battery Costs and Low Load Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$2,740	5.8	Yes
SDG&E	$453	$2,520	5.6	Yes
SDG&E and Centralized BESS in Valley South	$463	$2,520	5.4	Yes
Mira Loma	$309	$1,512	4.9	Yes
Mira Loma and Centralized BESS in Valley South	$363	$1,625	4.5	Yes
SCE Orange County	$748	$2,533	3.4	Yes
Menifee	$331	$2,381	7.2	No
Valley South to Valley North and Distributed BESS in Valley South	$200	$955	4.8	No
Valley South to Valley North	$205	$955	4.7	No
Centralized BESS in Valley South	$252	$1,032	4.1	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$255	$1,039	4.1	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$269	$1,036	3.9	No
Valley South to Valley North to Vista	$309	$1,036	3.4	No

The benefit-to-cost ratios for alternatives without BESS remain unchanged, but as anticipated, the alternatives with BESS improve in ranking. The Centralized BESS in the Valley South alternative has a significant improvement in benefit-to-cost ratio under this scenario. This is because this alternative relies solely on BESS to meet capacity needs in the Valley South System and therefore benefits the most from a reduction in BESS costs. The remaining alternatives with BESS improve as well but their lower benefits prevent significant improvement in benefit-to-cost ranking. Conventional alternatives such as Menifee, SDG&E and the ASP continue to rank high under this scenario. The incremental benefit-to-cost ratio advantage of ASP is unchanged because neither ASP nor SDG&E include BESS and they remain the two top ranked alternatives.

Table 8-11 shows the results of the benefit -to -cost comparison for the middle (Spatial Effective PV) forecast.

Table 8-11 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Reduced Battery Costs and Base Case Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$4,282	9.0	Yes
SDG&E	$453	$4,001	8.8	Yes
SDG&E and Centralized BESS in Valley South	$475	$4,041	8.5	Yes
Mira Loma	$309	$2,601	8.4	Yes
Mira Loma and Centralized BESS in Valley South	$439	$3,132	7.1	Yes
SCE Orange County	$748	$4,021	5.4	Yes
Menifee	$331	$3,882	11.7	No
Valley South to Valley North and Distributed BESS in Valley South	$203	$2,165	10.7	No
Valley South to Valley North	$207	$2,156	10.4	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$260	$2,479	9.5	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$272	$2,542	9.3	No
Valley South to Valley North to Vista	$290	$2,470	8.5	No
Centralized BESS in Valley South	$345	$2,535	7.4	No

As with the lower forecast, the alternatives with BESS improve in benefit -to -cost ranking under the base case (middle) load forecast scenario when BESS costs are halved. However, the reduction in BESS costs coupled with the lower benefits of the BESS alternatives in general does not change the relative ranking. An exception is the SDG&E and Centralized BESS which now performs slightly better than Mira Loma in overall benefit -to -cost ratio. The incremental benefit-to-cost ratio advantage of ASP is unchanged because neither ASP nor Menifee include BESS and they remain the two top ranked alternatives in the baseline incremental cost/benefit analysis.

Table 8-12 shows the results of the benefit -to -cost comparison for the high (Spatial Base) forecast.

Table 8-12 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Reduced Battery Costs and High Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$7,788	16.4	Yes
SDG&E	$453	$7,218	15.9	Yes
Mira Loma	$309	$4,766	15.4	Yes
Mira Loma and Centralized BESS in Valley South	$446	$6,604	14.8	Yes
SDG&E and Centralized BESS in Valley South	$537	$7,523	14.0	Yes
SCE Orange County	$748	$7,258	9.7	Yes
Menifee	$331	$7,201	21.8	No
Valley South to Valley North to Vista	$290	$4,617	15.9	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$317	$4,771	15.1	No
Valley South to Valley North and Distributed BESS in Valley South	$195	$2,736	14.0	No
Valley South to Valley North	$207	$2,618	12.7	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$486	$6,016	12.4	No
Centralized BESS in Valley South	$538	$6,008	11.2	No

Again, the results are substantially unchanged for the high load forecast scenario with 50% lower BESS costs. The superior incremental benefit-to-cost ratio of ASP is unaffected, as the ASP still has a 4.1 incremental benefit-to-cost ratio over the Menifee alternative.

8.5. Overall Sensitivity Analysis Results

The sensitivity analysis demonstrates that for reasonable downward adjustments in load forecast uncertainty and BESS costs, the option value of deferring capital investments needed to meet system requirements is not substantial. Overall, the substation solutions including the ASP have superior incremental benefit -to -cost ratios indicating that the significant capacity they add to the Valley South System and the multiple, useful system tie-lines are cost effective. Further, the analysis demonstrates that the conventional substation alternatives are more robust from the perspective of addressing future load growth uncertainties than other alternatives, providing margin for higher future load growth scenarios beyond those considered in this analysis.

9.0 Risk Assessment

This section of the Planning Study addresses risks of various alternatives that are not readily quantifiable in the context of the cost-benefit analysis.

9.1. Wildfire Mitigation Efforts and Associated Impacts on Alternatives

Minimizing wildfire risk is a critical consideration for SCE throughout the enterprise, including in project planning. Each of the project alternatives have substantially different profiles from a wildfire risk perspective. For the purpose of this Planning Study, a methodology based on the current Transmission Wildfire Risk Assessment and Mitigation Phase (RAMP) model was used to determine the relative contribution that each of the alternatives would make to increase the overall wildfire risk profile of the SCE system.

Currently, SCE's Transmission Wildfire Multi-Attribute Risk Score (MARS) baseline is 3.4[67] (out of 100) which is meant to demonstrate the relative risk exposure across SCE's portfolio. The MARS score is a unit-less value used to measure baseline risk, mitigation risk reductions (MRR), and the risk spend efficiency (RSE) of implementing various MMRs. To determine the potential increase in the baseline MARS score, the overhead circuit mileage of each alternative which is routed in Tier 2 and Tier 3 High Fire Risk Areas (HFRAs) is determined and multiplied by a representative incremental MARS per mile of overhead transmission factor. The results are summarized in Table 9-1.

[67] See Southern California Edison 2021 General Rate Case, "Risk Informed Strategy & Business Plan: SCE-01 Volume 02".

Table 9-1 – Incremental MARS Risk Contribution of Alternatives

Alternative	OH Length in HFRA (miles)	Incremental MARS Score	Percentage Increase Over MARS Baseline
SCE Orange County	24.6	0.015	0.43%
Alberhill	18.2	0.011	0.32%
SDG&E	16.2	0.010	0.29%
SDG&E with Centralized BESS in Valley South	16.2	0.010	0.29%
Mira Loma	4.9	0.003	0.09%
Mira Loma with Centralized BESS in Valley South	4.9	0.003	0.09%
Valley South to Valley North to Vista	3.8	0.002	0.07%
VS to VN to Vista with Centralized BESS in Valley South	3.8	0.002	0.07%
Menifee	1.2	0.001	0.02%
Centralized BESS	0.0	0.000	0.00%
VS to VN with Centralized BESS in Valley South	0.0	0.000	0.00%
Valley South to Valley North	0.0	0.000	0.00%
Valley South to Valley North and Distributed BESS in Valley South	0.0	0.000	0.00%

Table 9-1 demonstrates that the majority of the alternatives increase the baseline risk exposure to the overall wildfire risk profile of the SCE system, although the increase is minimal relative to the current baseline MARS score. The increase in risk as a whole is marginal and is therefore not incorporated into the cost models or considered a factor in evaluating the alternatives.

9.2. *Volatility in Peak Load*

The Valley South System currently serves peak load under normal weather conditions of approximately 1,000 MVA and is expected to experience load growth of approximately 10 MVA per year. The historical unadjusted recorded peak load values have demonstrated that the Valley South System can experience significant swings from year to year in the magnitude of peak load values and that even after typical normalizing adjustments are performed, a similar volatility remains present. This occurs because the system serves a large number of customers and even modest changes in circumstances can have dramatic impacts on the resulting electrical consumption.

Figure 9-1 shows that, for the Valley South System over the past ten years, the average year-over-year change (with some years being higher and some lower) in temperature-normalized loads was nearly 20 MVA. The two largest year-over-year swings were each over 50 MVA and were positive increases from the prior year. As seen in Figure 9-1, there are years where the year-over-year change was negative as well, with the actual total load growth averaging about 2% (~20 MVA) annually over that timeframe. This is important in that a forecast (represented generally by a forward-looking line reaching out over a time horizon) gives guidance directionally and in magnitude but does *not* represent the actual values that will occur year by year. Planning a solution to meet capacity needs predicated on the exact values that the forecast line suggests, and not fully acknowledging that the actual values likely to be recorded will deviate (both above and below) the forecast line, could result in a potentially significant underrepresentation of peak load values for any given year when load values fall above the line.

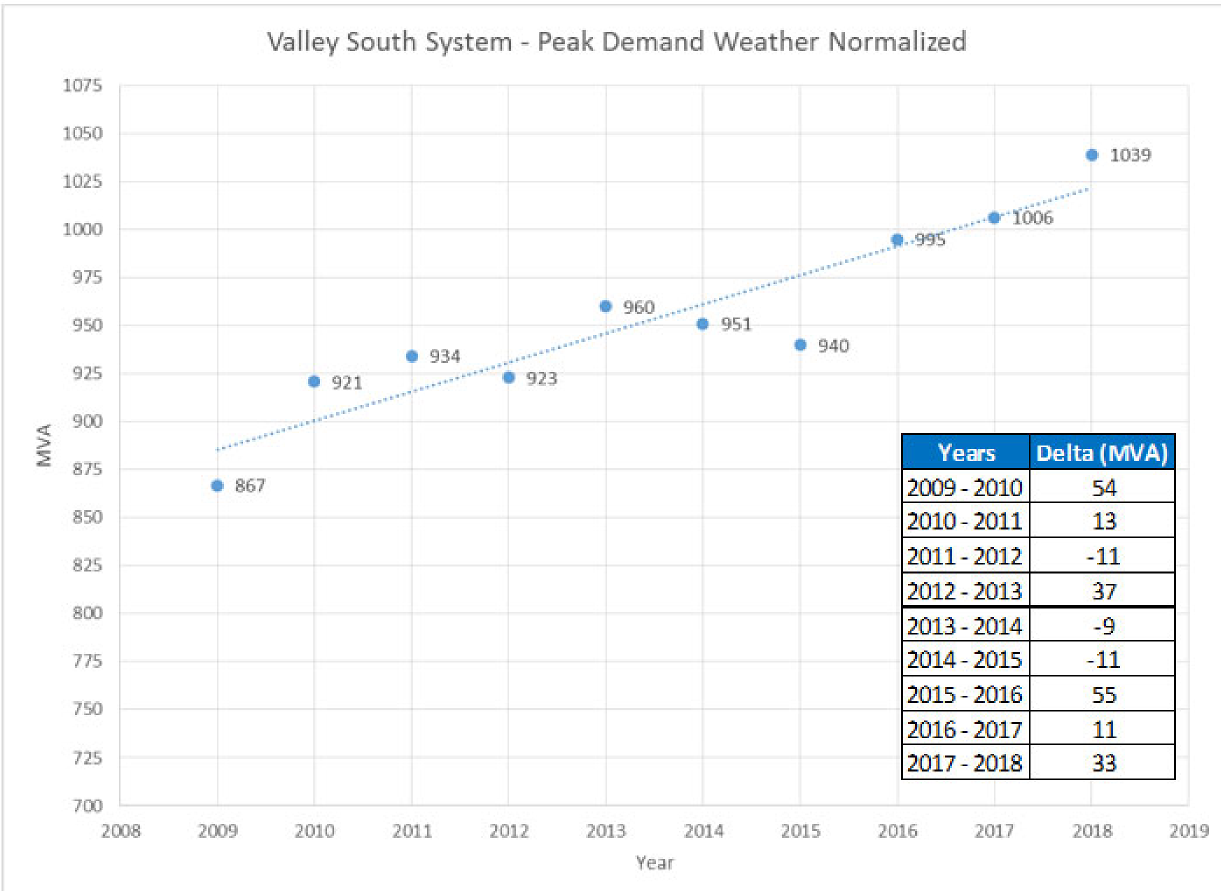

Figure 9-1 – Valley South System Peak Demand Weather Normalized

A consequence of relying on DER solutions applied incrementally to satisfy load growth is increased risk of being unable to serve load in a year that experiences peak demand that substantially exceeds the estimated demand. This element of risk is not accounted for in the cost-benefit analysis for NWA solutions. The risk can be effectively eliminated in Conventional Alternatives that provide additional inherent margin with respect to the forecast load.

9.3. *Effects of Climate Change*

Climate change that results in increased average and peak temperatures will have an effect on electricity demand and potentially, in extreme cases, to the behaviors and circumstances that drive the long-established correlation between temperature and load. Using historical load and closely correlated weather data, it was determined that when looking at peak temperatures, an increase in temperature of 1°F corresponds to an approximate 2.5 MVA increase in load at SCE’s Auld Substation (representative of a centrally located and generally typical distribution substation within the Valley South System). Scaling this up to the full Valley South System (14 substations in total) results in a 35 MVA increase in load for every 1°F rise in temperature. Other system-wide data suggest this correlation may be as low as a 1.9% increase in load per degree Fahrenheit. This range suggests that should such an increase in peak temperature materialize, the resulting increase in load of the Valley South System's transformers would be equivalent to the increase in load over a 2 to 3-year period based on the current forecast (average growth of ~10MVA/year). The overall effect would accelerate and amplify future capacity and reliability/resiliency deficits, resulting in capacity shortfalls occurring earlier than expected for all alternatives.

9.4. Potential for Greater than Expected Electrification Rates

The SCE and SLF load forecasts utilize the IEPR DER growth rates for the years 2019-2028, at which point the SLF utilizes the California PATHWAYS model to predict DER growth rates from 2028-2048. The CEC 2050 scenario of the PATHWAYS model is used in the extended Effective PV and PVWatts SLF, and therefore includes the "High Electrification" scenario considered in alternative iterations of the model. However, the SLF only considers forecast vehicle electrification and does not consider forecast building electrification beyond that which is already included in historical data. Additionally, the Spatial Base SLF scenario does not consider any DER growth, i.e., building electrification and vehicle electrification are not included. Should the aggressive targets associated with the CEC 2050 scenario be reached, the load forecasts presented in this Planning Study would likely prove to under-predict future realized load beyond 2028. Accordingly, alternatives with capacity margin and which are therefore not reliant on BESS, such as the ASP, SDG&E and SCE Orange County, perform more favorably in this scenario.

9.5. Licensing Delays for Alternatives

For simplicity, and to ensure that alternatives were evaluated in the cost benefit analysis on the basis of the value they present to customers independent of timing, all alternatives were assumed to be in service concurrent with the 2022 project need date. ASP has been substantially vetted through regulatory and public scrutiny and has a current expected in-service date of 2025. While this in-service date could potentially be accelerated with an expedited project decision, the other alternatives have not yet been fully designed and developed and have yet to undergo analysis, public engagement, and regulatory review under CEQA. As described in detail in Appendix C of this Planning Study, many alternatives include miles of new lines routes, proposed facilities in undeveloped locations, and extensive easement requirements.[68] These alternatives are expected to have substantial challenges in licensing due to:

- the specific nature of the routes (heavily populated suburban areas, reservations or parks) and or affected communities not being directly served or benefited by the project;
- prior experience with engagement of the affected communities;
- unforeseen issues that may emerge through the CEQA process; and

[68] The site and route descriptions and associated characteristics affecting licensing durations (miles, property acquisitions, communities affected, undeveloped land, etc.) are described in Appendix C for each of the alternatives.

- required CAISO approval of the SDG&E alternative and risk of SDG&E opposition to relinquishing substantial capacity that would otherwise be available to support their own internal load growth.

As a result, several of these projects would be expected to have extended, multi-year licensing timelines that could extend to near the end of the ten-year project planning horizon, potentially resulting in risk and unrealized benefits to customers during this period or the need for other costly interim mitigations. For each year of delay, the reduction in overall benefits to customers would increase, starting from a range of $4.3M to $148M.[69] If these likely licensing delays and associated cost and benefit impacts were to be monetized in the cost-benefit analysis, the alternatives with expected longer licensing durations would perform much less favorably.

The consequence of project delays is risk of loss of service to customers which is masked to some extent in the assignment of probabilities to individual event scenarios. When one considers the real possibility of N-2 line and substation events occurring and that these probabilities are enhanced at periods of time when the systems are most vulnerable (high temperatures and high loading conditions), the consequences of these events are more apparent. For example, in considering the real possibility of a Flex-2-1 type event[70] occurring in 2028 on or near a peak load day without an appropriate project in place (i.e., one with adequate capacity and effective tie-lines and diverse location) the impact would be:

- Over 200,000 metered customers (>500,000 people) would lose service with no means to practically restore load in a timely manner

- The region would experience large scale economic impacts as well as disruption of public services

- Customer financial impact in the billions (based on VoS study outage costs as well as published costs of recent widespread outages)[71]

Similarly, while the impact on N-2 line outages would be somewhat more localized than for substation N-2 events, the consequences are also large. As an example, with no project in place, if a single 4-hour N-2 outage were to occur for the Valley-Auld #1 and Valley-Auld #2 115 kV lines (which have a number of common poles) on a peak day in 2028 approximately 35,000 customers would lose service for this period. Based on the VoS Study, the cost to customers of this single event would be on the order of $55M. Other credible line outage combinations would have similar impact. This economic impact occurs in both the case of substation and line N-2 events, because without a project to add capacity and serve load in an alternative manner (e.g., through transfers using system tie-lines), load shedding would be required to mitigate overload conditions. The ASP

[69] In 2022, the Valley South to Valley North Alternative provides $4.3M and the ASP provides $148M of benefits to customers. These benefits increase in subsequent years.

[70] Total loss of the power delivery to the Valley South System for a 2-week (minimum) outage to (remove, transport, and replace transformers, repair bus work, replace power and control cables, etc.)

[71] https://www.cnbc.com/2019/10/10/pge-power-outage-could-cost-the-california-economy-more-than-2-billion.html

fully mitigates this loss of service to customers, while other alternatives provide only modest improvements at best. Table 9-2 below provides the cost to customers for this N-2 outage with each alternative implemented.

Table 9-2 - Customer Costs for Valley-Auld #1 and Valley-Auld #2 Outage: Peak Day in 2028

No Project	ASP	SDG&E	Mira Loma	SCE Orange County	VS-VN	VS-VN-Vista	Centralized BESS	Menifee
$55.6M	$0M	$44.4M	$55.6M	$55.6M	$55.6M	$55.6M	$44.9M	$55.6M

Note: Results for hybrid alternatives are not provided, as all BESS deployments for hybrid alternatives occur after 2028.

9.6. Licensing of Incremental Capacity Solutions

The regulatory pathways for licensing and implementing incremental energy storage projects or DER solutions are evolving in California and thus the ability to source the incremental capacity needs for some of the alternatives on a timely basis is uncertain. Similarly, the reliability of third-party delivery of these incremental capacity solutions is not yet proven to meet utility standards. Because these concerns are expected to be resolved well before these capacity additions are needed and associated costs are likely to be bounded by the costs of the modelled BESS alternatives, they are not considered to be significant risks.

9.7. Cannabis Cultivation Risk

SCE's planning department engages with local area businesses and customers to stay abreast of projects that may result in changes to electrical load. The cultivation of cannabis is a recent phenomenon that SCE estimates will result in an increase of approximately 5 MW in the Valley South System and 10 MW in the Valley North System within the ten-year planning horizon. This type of load is not represented in the historical data and is not included in the IEPR forecasts, nor is it explicitly represented in the Planning Study. Therefore, for any proposed solutions that seek to provide just enough capacity to meet the projected load without any additional marginal capacity, there is risk introduced that these particular solutions may not be sufficient to meet the demand should this load materialize.

9.8. Energy Storage Wholesale Market Revenue Risk

The current cost estimates for alternatives that employ BESS contain market revenue adjustments that bring down the overall cost of the solution. This market revenue is based on well-founded assumptions utilizing typical capacity and frequency regulation market participation scenarios, locational marginal pricing (LMP) data, and realistic round-trip efficiency models of BESS. There is uncertainty, of course, associated with these assumptions, particularly the LMP data, as the revenue gained from participating in wholesale markets can fluctuate from day-to-day and will vary in the future as market needs evolve. Particularly, as large-scale renewable energy developments in the Southern California region continue to drive down the total cost of generation,[72] the revenue realized by market participation may indeed be less than the figures estimated in this Planning Study.

9.9. Potential Need for 500 kV Generator Interconnection Facility

ASP is currently identified as the interconnection facility for the Lake Elsinore Advanced Pumped Storage (LEAPS) project[73] and, as designed, is able to accommodate a future interconnection. Should the LEAPS project be realized and a project other than ASP be selected, a new 500 kV substation (e.g., switching substation) would need to be developed in the area to support the LEAPS project as required by the Large Generator Interconnection Agreement (LGIA) between the developer of the LEAPS project and SCE.

9.10. Regulatory and Pricing Uncertainty for Demand Side Management Alternatives

Several forms of demand side management (DSM) were considered as part of SCE's alternatives analysis, including residential, non-residential, and plug-in electric vehicle (PEV) based load modifying DSM. Expansion of both residential and non-residential DSM programs currently in place would require either substantial changes in the regulatory framework (in the case of reliability offerings, a raising of the 2% cap on total system capacity[74]) or significant investment above and beyond current program expenditures with uncertain return given the current scale of DSM operations in the region. SCE's Customer Programs & Service organization analyzed existing programs and found that additional investment in the programs, without regulatory modification, would not result in any substantial reduction in future load beyond current capabilities. For economically dispatched programs, current scalable offerings in the residential space have reached a large degree of saturation for cost-effective DSM program participants in the region. Recent efforts to recruit new participants in the region have been to maintain the current levels of program capacity or have seen smaller incremental gains. With PEVs, a version of DSM would incorporate charging electric vehicle service equipment (e.g., PEV chargers) as a controlled load, effectively mitigating some portion of future load growth due to PEV adoption. However, there is significant uncertainty with this approach as very little historical data is available to make a reasonably accurate assessment of the impact of such a program.

Accordingly, for the purpose of this Planning Study, BESS are used as a surrogate for DSM program capacity/energy (or other DERs) that might ultimately be incorporated in Hybrid Alternatives. While it is recognized that DSM cost structures may vary from those of BESS, there is no framework to consider what these costs might be ten to thirty years from now to satisfy incremental capacity needs at that time. BESS costs are somewhat more predictable based on published long-term market data. Therefore, there is some risk that BESS costs in the cost benefit

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[72] See "Los Angeles OKs a deal for record-cheap solar power and battery storage", Los Angeles Times, Sept 20, 2019.

[73] The hydroelectric license application for LEAPS is currently pending before the FERC in Docket No. P-14227-003

[74] CPUC Decision D.10-06-034 adopted a reliability-based demand response settlement agreement that capped reliability-based demand response program that count toward resource adequacy at 2% of the recorded all-time coincident CAISO system peak, starting in 2014.

analysis model may be higher than those that might be realized in a future procurement of DSM resources. However, since these future costs are discounted heavily in the model and because DSM would almost certainly need to be augmented with some amount of BESS capacity due to the large capacity and energy needs that arise near the end of the evaluation period, it is unlikely that the results of the cost benefit analysis are substantially impacted by this assumption. From an implementation standpoint, if a hybrid alternative is selected, SCE can, under the appropriate regulatory framework at the time, build or source available front-of-the-meter and behind-the-meter DER technologies at market prices to meet the incremental capacity needs.

10.0 Basis for Preferred Alternative

This planning study confirms the need for a project and more specifically reinforces selecting a comprehensive solution for the Valley South System that addresses the transformer capacity shortfall forecast for 2022 and provides adequate system tie-lines to another system in order to improve reliability and resiliency. The ASP is SCE's recommended solution[75] to best address the defined objectives for the project based on a variety of factors. The ASP addresses the current and future capacity, reliability, and resiliency needs of the Valley South System, and most effectively meets all objectives defined at the onset of the project proceedings for the Valley South System. Further, the ASP is a long-term, cost-effective solution, and can be implemented in a reasonable time. Lastly, the ASP is a robust solution that limits SCE's risk exposure during unforeseen scenarios during implementation and while in operation.

Project Objectives

Serve current and long-term projected electrical demand requirements in the Electrical Needs Area (ENA). The ASP would meet the forecasted electrical demand and satisfy SCE Subtransmission Planning Standards and Guidelines related to substation transformer capacity until the year 2048.[76] ASP effectively addresses uncertainty and volatility in future load.

Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer substations from the current Valley South 115 kV System. The ASP would create the system tie-lines necessary to allow for operational flexibility and the ability to transfer substations from the Valley South System when needed for planned maintenance outages and to address multiple unplanned contingencies. The system analysis performed to support the 2019 data requests shows that the ASP would provide substantial available flexibility under specific contingency scenarios.[77]

Transfer a sufficient amount of electrical demand from the Valley South 115 kV System to maintain a positive reserve capacity on the Valley South 115 kV System through the 10-year planning horizon. The ASP would result in additional capacity in the region sufficient to provide positive reserve capacity on the Valley South System through and beyond the 10-year planning horizon.[78,79] In providing an additional source of

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[75] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item I.

[76] See Section 6.4 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C. The ASP satisfies transformation capacity needs far beyond 2048. A minor project to reconductor a single subtransmission line would be required in the 2038 time frame to satisfy N-1 line violation criteria through 2048.

[77] See Section 5 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item F.

[78] See Appendix B, Section 1, and Section 6.4 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

[79] The initial construction of the ASP is proposed to include two 560 MVA transformers of which one would be considered load-serving and the second would be an in-service spare. SCE notes that 1,120 MVA is a large amount of capacity to add to the system considering the incremental system needs of about 10 MVA per year. However, the

power it provides Valley South capacity relief without decreasing capacity margins in adjacent systems.

Provide safe and reliable electrical service consistent with SCE's Subtransmission Planning Criteria and Guidelines.[80] The ASP relieves all undesired exceptions to SCE's Subtransmission Planning Criteria and Guidelines that have been taken as the Valley South System has evolved.[81]

Increase electrical system reliability by constructing a project in a location suitable to serve the Electrical Needs Area (i.e., the area served by the existing Valley South System). The Final Environmental Impact Report (FEIR) and the analyses for the ASP demonstrate that the project siting and routing is attractive from the perspective of electrical system performance in serving the Electrical Needs Area. Its location in the San Jacinto Valley Region is within the area that directly benefits from the project. In addition to providing a second source of power to the region, the Alberhill Substation in the ASP is proposed in a geographic location distinct from Valley Substation where improvements to system reliability and resiliency would result.

Meet project need while minimizing environmental impacts. The ASP would meet the project need and has been determined in the FEIR to be the environmentally preferred alternative relative to the 30 alternatives considered therein ("FEIR Alternatives").

Meet project need in a cost-effective manner. As demonstrated in the cost-benefit analysis,[82] the ASP is a cost-effective solution. Among alternatives considered, the ASP is the lowest cost project alternative that fully satisfies the project objectives and capacity, reliability, and resiliency needs over both short and longer-term planning horizons.

Performance Metrics

SCE developed and evaluated the performance of a robust list of 12 project alternatives in addition to the ASP.[83] These alternatives included substations; subtransmission lines that transfer load to

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basis for this is as follows: 1) the ASP includes the addition of two transformers to satisfy SCE and industry-wide N-1 contingency planning criteria. These criteria require a subtransmission system be able to withstand an outage of any single subtransmission system element without disruption of service to customers. The second 560 MVA transformer is the on-site spare. 2) SCE's standard transformer size for 500/115 kV substations is 560 MVA and the potential savings from procuring a smaller capacity custom transformer is relatively small and would likely be offset by the costs of engineering and designing a non-standard transformer. 3) A uniquely sized 500 kV transformer would negate benefits achieved from using standard sized equipment between the 500/115 kV systems (i.e., Valley and Alberhill). 4) Lastly, approximately 400 MVA of demand is proposed to be initially transferred from the Valley South System to the Alberhill System and this equates to an approximate 70% utilization of the 560 MVA load-serving transformer initially and it is expected that this utilization would increase over time with load growth in the area.

80 See SCE Subtransmission Planning Criteria and Guidelines 9/2015.

81 See Table 4-1 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

82 See Section 8.2 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

83 The alternatives developed in response to this data request were based on a variety of inputs including stakeholder feedback and are in addition to the 30 "FEIR Alternatives" that were considered during the CEQA process and were

adjacent systems; battery energy storage systems (BESS); and combinations of the above. The ASP and these alternatives were evaluated using objective, quantitative, and forward-looking metrics to quantify their effectiveness in addressing capacity, reliability, and resiliency needs over time. The results showed:

- The ASP ranks first among the alternatives in terms of project performance in meeting objectives over both the 10-year (2028) and the 30-year (2048) planning horizons. The ASP resolves over 96%[84] of the projected capacity, reliability, and resiliency shortfalls in the region through 2048. Other alternatives resolve at most 83% of the projected shortfalls through 2048. When considering only lower-cost alternatives, only 34% of shortfalls are resolved through 2048. Similar percentage reductions are observed for the short-term (10-year planning horizon).
- All alternatives with lower costs than the ASP require SCE to implement incremental future investments to maintain compliance with SCE's Planning Criteria and Guidelines over the next 30 years and do not achieve system reliability and resiliency improvements comparable to the ASP. The ASP is the only solution that does not require incremental capacity additions to address electric service interruptions due to transformer capacity shortfalls through 2048. Menifee, a lower cost alternative that meets long-term capacity needs, does not have system tie-lines that are effective in transferring additional load from the Valley South System to an adjacent system during abnormal system conditions (e.g., N-1 or N-2 contingency conditions). The ineffective system tie-lines result from the Menifee alternative substation's location which is essentially adjacent to Valley Substation. Constructing effective system tie-lines at this location would require complex and expensive scope additions because of the location at the hub the Valley South System. Generally, and in this case, system tie-lines are most effective and economic when constructed near the periphery of a radial subtransmission system for reasons described in Section 8.2.1. Additionally, the proximity to Valley Substation introduces the potential vulnerability to HILP events affecting both Menifee and Valley substations and this vulnerability is not reflected in the resiliency metrics included in the current analysis.

Cost Effectiveness

The cost effectiveness of the ASP and alternatives to the ASP is evaluated by estimating the monetary value for each alternative from the perspective of the value of electric service to customers over total project costs. The ASP is cost effective in providing substantial benefits to customers. Specifically:

- The ASP has the best incremental benefit-to-cost ratio relative to alternatives considered, and among all sensitivity cases considered indicating that its increased benefits relative to these alternatives are cost effective.

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deemed less favorable than the ASP. The data request alternatives are described in detail in Section 6 and Appendix C. As directed by the CPUC, SCE did not evaluate any of the FEIR Alternatives other than the ASP in the data request submittals; as the ASP was already deemed to be superior to the FEIR Alternatives.

[84] Calculated as the total reduction in LAR for capacity, reliability, and resiliency metrics through 2048. See Table 6-2.

- The ASP has an overall benefit-to-cost ratio greater than nine, which is highly ranked among the 13 total alternatives in cost-benefit analysis and first among projects that meet project objectives. The other highly ranked alternatives that meet project objectives are the Mira Loma and SDG&E alternatives; however, these two alternatives violate the N-0 transformer overload system planning criteria (capacity) in 2031 and the 2040 time frame respectively and sooner under even modestly higher load forecast scenarios. This is an indication that they are less robust than ASP from a capacity perspective. When the subsequent investments needed to address the capacity violations and subsequent continuing incremental capacity needs (e.g., the addition of BESS over time to address capacity shortfalls) are considered, both the Mira Loma and SDG&E alternatives are ranked even farther below the ASP in terms of benefit-to-cost ratio.

Optionality and Risk

When considering a variety of optionality and risk factors including uncertainty and volatility in load, potential technology or market changes, and risks associated with project costs, ASP is the preferred solution over lower cost project alternatives to meet system needs over a shorter timeframe.

- ASP remains cost-effective under future low load growth and low -cost DER scenarios; while lower cost, short -term alternatives are not effective in addressing future higher load growth scenarios (such as might occur with enhanced electrification).
- ASP is more effective than lower cost, short -term alternatives in addressing other system performance risks such as those associated with year -to -year volatility in load and degraded capacity margins in adjacent systems.
- ASP has lower risk associated with ultimate licensing and cost of implementation than other alternatives that have not been subject to years of design, analysis and stakeholder engagement as has been the case for ASP. The project risks that could lead to higher costs or other concerns during the development, design and licensing include: required undergrounding commonly associated with projects with lengthy subtransmission lines constructed through congested areas; unknown geotechnical conditions; rerouting to avoid areas with stakeholder concerns and potential challenges associated in reducing capacity margins in the SDG&E system.

Timeliness of Project Implementation

SCE and other utilities propose projects well in advance of the need date in order to have infrastructure licensed, constructed, and operational in time to meet the need. Given the time required for licensing, SCE applied for a project in the Valley South System years in advance of its need, to avoid jeopardizing reliable service to its customers. The ASP licensing process has been underway for over a decade now. The need for a project in the Valley South System in the 2022 timeframe has been confirmed through SCE's supplemental analysis.[85] ASP has been substantially vetted through regulatory and public scrutiny and has a current expected in -service date of 2025. While this in -service date could potentially be accelerated with an expedited project

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[85] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.

decision, the other alternatives have not yet been fully designed or developed and have yet to undergo analysis, public engagement and regulatory review under CEQA. This additional work will result in continued project licensing costs to ratepayers and a higher probability of unexpected developments that would contribute to further delay.

A Appendix - Capacity, Reliability, and Resilience

Capacity is the availability of electric power to serve load and comprises two elements in a radial system: 1) transformation capacity – the ability to deliver power from the transmission system (provided by the substation transformers), and 2) subtransmission system line capacity – the ability to deliver power to substations which directly serve the customer load in an area. Both transformation capacity and subtransmission system line capacity include providing sufficient capacity under both normal and abnormal system conditions as well as under adverse weather conditions (e.g., 1-in-5 year heat storm conditions). Included in subtransmission system capacity is system tie-line capacity, the capacity to transfer load to an adjacent subtransmission system to maintain electrical service under a variety of system conditions or activities, such as planned outages for maintenance or new construction and unplanned outages. The lack of capacity of either type can lead to reliability challenges in a radial power system.

Reliability refers to a utility's ability to meet service requirements under normal and N-1 contingency conditions,[86] both on a short-term and long-term basis. Reliability is focused on the impacts to the electric grid and the associated effects on the day-to-day customer experience as it relates to power outages and durations thereof. It is conventionally quantified by metrics (such as those defined by IEEE-1366) that demonstrate how well a utility limits the frequency and duration of localized outages from factors such as equipment failure, animal intrusion, damage introduced by third parties, and the number of affected customers during these outages.

Resilience refers to a utility's ability to keep its systems functioning and serving customers under extraordinary circumstances.[87] Resilience is focused on how well the utility anticipates, prepares for, mitigates, and recovers from effects of extraordinary events. Wildfires, earthquakes, cyber-attacks, and other potential high impact, low probability (HILP) events can have widespread impact on the utility's ability to serve customers. Resilience also includes preparedness for long-term permanent changes such as the effects of climate change. Resilience is not just about continuing operations, but also is about the effectiveness of containing the impact of these extraordinary events and how efficiently and quickly a system and/or service is restored.

Key differences between reliability and resilience include:

Reliability	**Resilience**
• Normal circumstances	• Extraordinary events
• Localized impact	• Widespread impact
• Design redundancy	• Design and operations flexibility
• System capacity/contingency-based planning criteria	• Comprehensive consideration of risk and mitigation
• Customer outage focused	• Customer outage ***and*** utility operations focused

[86] An N-1 contingency is an unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element.

[87] See IEEE PES-TR65 "The Definition and Quantification of Resilience", April 2018 for more information.

B Appendix - History of the Valley Systems

B.1 Calectric Merger and Early History

Prior to 1964, the San Jacinto Valley Region was provided electrical service by the California Electric Company (Calectric). The region was served by the 115/33 kV Valley Substation (operated as a single radial subtransmission system) which was provided power by the 115 kV system from Vista Substation. Voltage was stepped down to 33 kV at Valley Substation and then distributed to the distribution substations via 33 kV source lines.

When SCE and Calectric merged in 1964, SCE became responsible for planning and operating these facilities. Long-range planning estimates from this era identified that due to projected load growth, the single 100 MVA 115/33 kV transformer that served the electrical needs of the entire 1,200 square-mile region would be insufficient to meet the growing demand and that system upgrades and additions would be required in the near-term future. These included capacity additions throughout the region (including capacity additions at Valley Substation and its distribution substations) and upgrades to the 33 kV source lines to the distribution substations emanating from Valley Substation to transport more power more efficiently. The 115 kV voltage was already present in the area as a source line to the Valley 115/33 kV Substation from the Vista 220/115 kV Substation to the north. It was determined that Valley Substation would eventually need to be converted to a higher voltage on the source side to deliver the additional required power and then the lower voltage 33 kV system would, at the same time, be converted to 115 kV. This would also then necessitate the conversion of the downstream 33/12 kV distribution substations to 115/12 kV. The 115 kV lines from the Vista System, previously providing the source power to Valley Substation, would be retained as subtransmission system tie-lines as part of a newly formed 115 kV system.

Throughout the 50,000 square mile service territory that resulted from the SCE and Calectric merger, the predominant transmission voltage was 220 kV, providing service to 220/115 kV and 220/66 kV A-bank substations. SCE's typical A-bank substations operating at these voltages were designed for an ultimate capacity of 1,120 MVA. Since it was projected that the ultimate load to be served in the entire San Jacinto Region would be approximately 1,000 MVA, Valley Substation was anticipated to be converted to a typical 220/115 kV transmission substation. In this case, new 220 kV transmission lines would have been constructed, from existing 220 kV facilities approximately 20 miles to the north, to provide the source power.

These plans were revised as new information became available. Load growth in Orange County and portions of Los Angeles County necessitated additional high-voltage transmission line facilities to deliver power from generation located further east. In the 1980s, a 500 kV transmission line was planned which would connect SCE's Serrano Substation in Orange County to SCE's Devers Substation in the Palm Springs area in order to deliver power from the Palo Verde generation station located in Arizona. Recognizing the transmission capacity needs of the coastal areas, along with the localized capacity needs in the San Jacinto Region, and that the planned route of the 500 kV line would pass near Valley Substation, the plan was then modified to convert Valley Substation to a 500/115 kV substation rather than a 220/115 kV substation, as this would involve significantly less transmission line construction. The resulting 500 kV lines would be the Devers-

Valley and Serrano-Valley 500 kV Transmission Lines, and Valley Substation would become a 500/115 kV A-bank substation.

The conversion of Valley Substation included leveraging the high capacity of the 500 kV transmission system to deliver power to the area by installing two 560 MVA 500/115 kV transformers (versus the typical 280 MVA transformers used at 220/115 kV or 220/66 kV substations) with one to serve demand and the other to function as a spare. The distribution substation source lines were rebuilt and converted from 33 kV to 115 kV and the distribution substations were rebuilt to 115/12 kV. With the newly created 115 kV lower voltage subtransmission system, the original 115 kV source lines to Valley Substation were then used as 115 kV subtransmission system tie-lines to the Vista 220/115 kV System.[88]

In 1984, the new Valley 500/115 kV System conversion was complete. The new radial 115 kV system served the entire 1,200 square-mile San Jacinto Region, including what is currently the Valley North and Valley South 115 kV Systems. Over time, more of the agricultural land was rezoned for development, and in the late 1980s it became apparent that the 1,000 MVA anticipated ultimate demand expected for the area was significantly underestimated. Prior to electrical demand exceeding the capacity of the single 560 MVA load-serving transformer, the existing spare transformer was converted to function as load-serving and a new spare was ordered and installed. This resulted in Valley Substation consisting of a single 115 kV radial system served by two 560 MVA transformers with a third transformer functioning as an on-site spare.

In the early 2000s, the area experienced further unprecedented growth in electrical demand due to housing development as more and more people elected to reside in the San Jacinto Region and commute to Orange and San Diego Counties. Planning activities identified that by 2003, peak demand would exceed the installed transformer capacity at Valley Substation. Both immediate and long-term solutions were needed. As before, SCE placed the existing spare transformer in-service and ordered and installed a new spare. However, load growth in this area was continuing at a very high rate (75-100 MVA per year or ~8% annually) and it was expected that, within just a few years, additional capacity would again be needed.

B.2 Developing a Long-Term Solution

Along with having three load-serving 560 MVA 500/115 kV transformers operating electrically in parallel and needing further transformation capacity to address load growth, SCE identified several other issues that needed to be resolved in the Valley System. These included short-circuit current values that were exceeding or encroaching on equipment ratings as well as reliability and resiliency concerns of serving so many customers over such a large area from a single radial electrical system.

By this time, the California Public Utilities Commission General Order 131-D was in place and the time required to perform the necessary environmental studies and obtain approvals would not allow for a long-term solution to be constructed before the capacity of the three transformers was

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[88] These 115 kV system tie-lines currently connect the Valley North System to the Vista System.

projected to be exceeded. As an interim solution, in 2004, SCE decided to split the single 115 kV system into two separate 115 kV systems (Valley North and Valley South) by constructing new facilities at Valley Substation and placing the spare transformer in-service as the fourth load-serving transformer. The substation was configured so there would be two transformers serving each system. The scope of work included constructing a new 115 kV switchrack on the south end of the property, converting the spare transformer to a load-serving transformer, connecting two of the four transformers to each 115 kV switchrack, and reconfiguring the 115 kV lines to roughly split the load between the two systems. By 2005, this work had been completed.[89] The resulting design met the immediate transformer capacity needs but left other issues to be resolved through the development of a long-term solution.

The first unresolved issue included addressing the long-term reliability needs of the region, which included assessing A-bank substation transformer capacity and system transfer capacity (i.e., sufficient system tie-line capacity). A second unresolved issue was to address the resiliency vulnerabilities associated with serving such a large customer base from a single radial A-bank substation - particularly considering its unique 500/115 kV transformers which precluded having ready access to spares as would have been the case with the typical 220/66 kV or 220/115 kV transformers. Associated with both reliability and resiliency, was the need to address that the Valley South System had no system tie-lines. Following the in-servicing of the fourth transformer and splitting the Valley System into two separate electrical systems, the existing four system tie-lines to the Vista System were now all part of the newly formed Valley North System and thus the Valley South System was left with none. Finally, after placing the existing spare transformer in-service to serve load, Valley Substation (and the Valley North and Valley South Systems) were left without a spare transformer. This was inconsistent with SCE's planning criteria and was also inconsistent with how SCE had designed its other radial electrical systems.

In developing a long-term solution to address the expected future growth and to the unresolved issues identified above, SCE evaluated past load growth trends and anticipated future load growth projections as well as expected changes in land use and load types that would affect load. This led SCE to review various solutions to meet the anticipated needs in both the near-term and long-term horizons. These solutions included load-shifting from system to system, transformer capacity additions, system tie-line creation, and generation. The fundamental requirements of any solution were to address transformer capacity deficits, lack of system tie-lines, and the diversification of the sources of power that would serve the region.

B.3 Alberhill System Project

The long-term planning demonstrated that the load growth potential of the region would require significantly more capacity than what could be served from Valley Substation, due primarily to transformer capacity needs and a lack of system tie-lines. Given the long-term forecast based on an unprecedented development boom, and prior to the proliferation of distributed generation in the form of roof-top PV, SCE identified a future need for multiple new A-bank transmission substations (and their associated new radial electrical systems) over time as development

[89] This work resulted in the current system configuration which is shown in Figure 3-2.

continued. This would be a comprehensive method for addressing the long-term electrical needs of the region by adding transformer capacity, addressing the lack of system tie-lines, and diversifying the sources of power.

The ASP was the initial preferred option for these new regional electrical improvements because: 1) the Valley South System had the most immediate transformer capacity need; 2) the Valley South System had no system tie-lines (inconsistent with SCE's planning practices) and was therefore isolated from adjacent electrical systems; and 3) the Alberhill System Project would have the least amount of transmission line related scope and was therefore expected to be completed soonest.

The Alberhill System Project will address capacity and reliability issues in the Valley South System specifically, and in addition, improve the resiliency of the larger Valley System. The Alberhill System Project includes the construction of a new 500/115 kV substation with two 500/115 kV 560 MVA transformers and the formation of system tie-lines between the newly constructed Alberhill System and the existing Valley South System. Approximately 400 MVA of electrical demand would be served through the initial transfer of five 115/12 kV distribution substations (Ivyglen, Fogarty, Elsinore, Newcomb, and Skylark) and would reduce the loading on the Valley South System. The transfer of these substations was chosen due to their proximity to the Alberhill Substation site, as well as the amount of load relief that would be provided to the Valley South System. The project strives to minimize the amount of new 115 kV line construction and/or reconfiguration required to achieve the transfers, with consideration of the tie-line capacity that would be created. Figure B-1 shows the proposed new Alberhill System in the context of the Valley North and Valley South Systems.

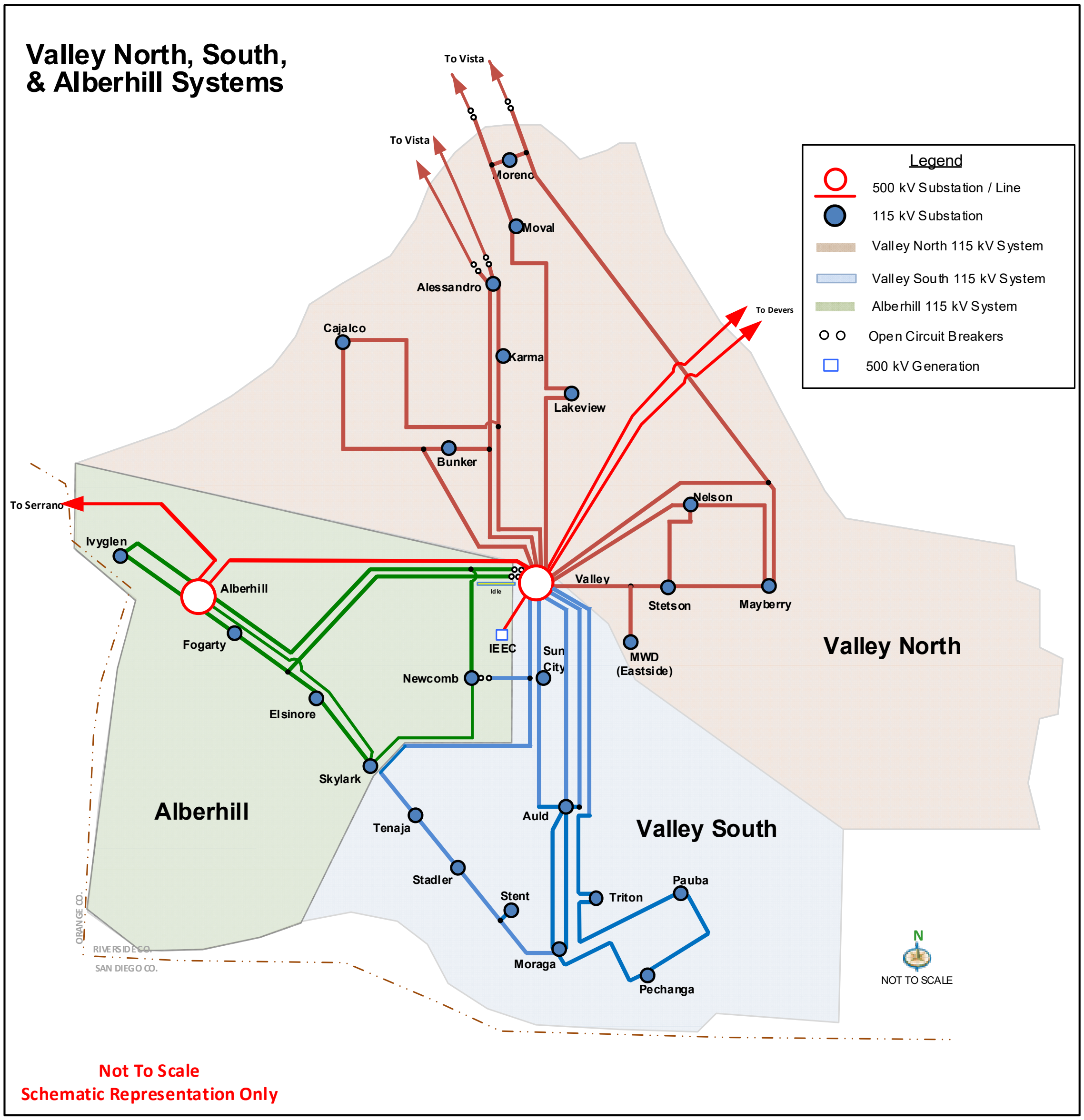

Figure B-1 – Proposed Alberhill, Valley South, and Valley North Systems

While load growth in the Valley South System slowed from the extraordinary levels seen through the early 2000s, load growth is continuing through today and the future need for additional capacity that was first identified in 2005 has now reached a critical point.[90] The current lack of sufficient transformer capacity margin, particularly coupled with limited operational flexibility resulting from the lack of system tie-lines, is a near-term threat to the reliability of the Valley South System. Additionally, the resiliency of the Valley South System continues to be limited because it is served

[90] This fact is reflected in sequential SCE 2017 and 2018 load forecasts covering the years 2018-2027 and 2019-2028 respectively. The additional, independent load forecasts provided in this Planning Study underscore the criticality of this project.

from a single source of power at Valley Substation and because it has no system tie-lines to at least partially mitigate the potential loss of service from certain power lines within the system and/or an unplanned outage of all or part of the Valley Substation.

The Alberhill System Project would meet the project objectives by adding A-bank substation transformer capacity and system tie-line capacity to the existing area served by the Valley South System while also diversifying the location of the new power source to the area. The reliability and resiliency of the entire region would be greatly improved by increasing the transformer capacity, adding system tie-lines (absent since 2005), and diversifying the locations of the source power.

C Appendix – Project Alternatives Descriptions

This appendix provides details of the project alternative system overviews, schematics, siting and routing descriptions and maps, implementation scope, and cost estimates.

C.1 Alberhill System Project

C.1.1 System Solution Overview

The Alberhill System Project (ASP) proposes to transfer load away from Southern California Edison's (SCE) existing Valley South 500/115 kilovolt (kV) System to the new 500/115 kV Alberhill System via construction of a new 500/115 kV substation and looping in the Serrano-Valley 500 kV transmission line. The project would include 115 kV subtransmission line scope to transfer five 115/12 kV distribution substations (Fogarty, Ivyglen, Newcomb, Skylark and Elsinore) currently served by the Valley South System to the new Alberhill System. Subtransmission line construction and modifications in the Valley South System would also create three system-ties between the Valley South System and the newly formed Alberhill System. The system-tie lines would allow for the transfer of load from the new Alberhill System back to the Valley South System (one or all of Fogarty, Newcomb, Skylark and Elsinore) as well as additional load transfer from the Valley South System to the new Alberhill System (Tenaja Substation) as needed.

C.1.2 System One-Line Schematic

A System One-Line Schematic of the ASP is provided in Figure C-1 on the following page.

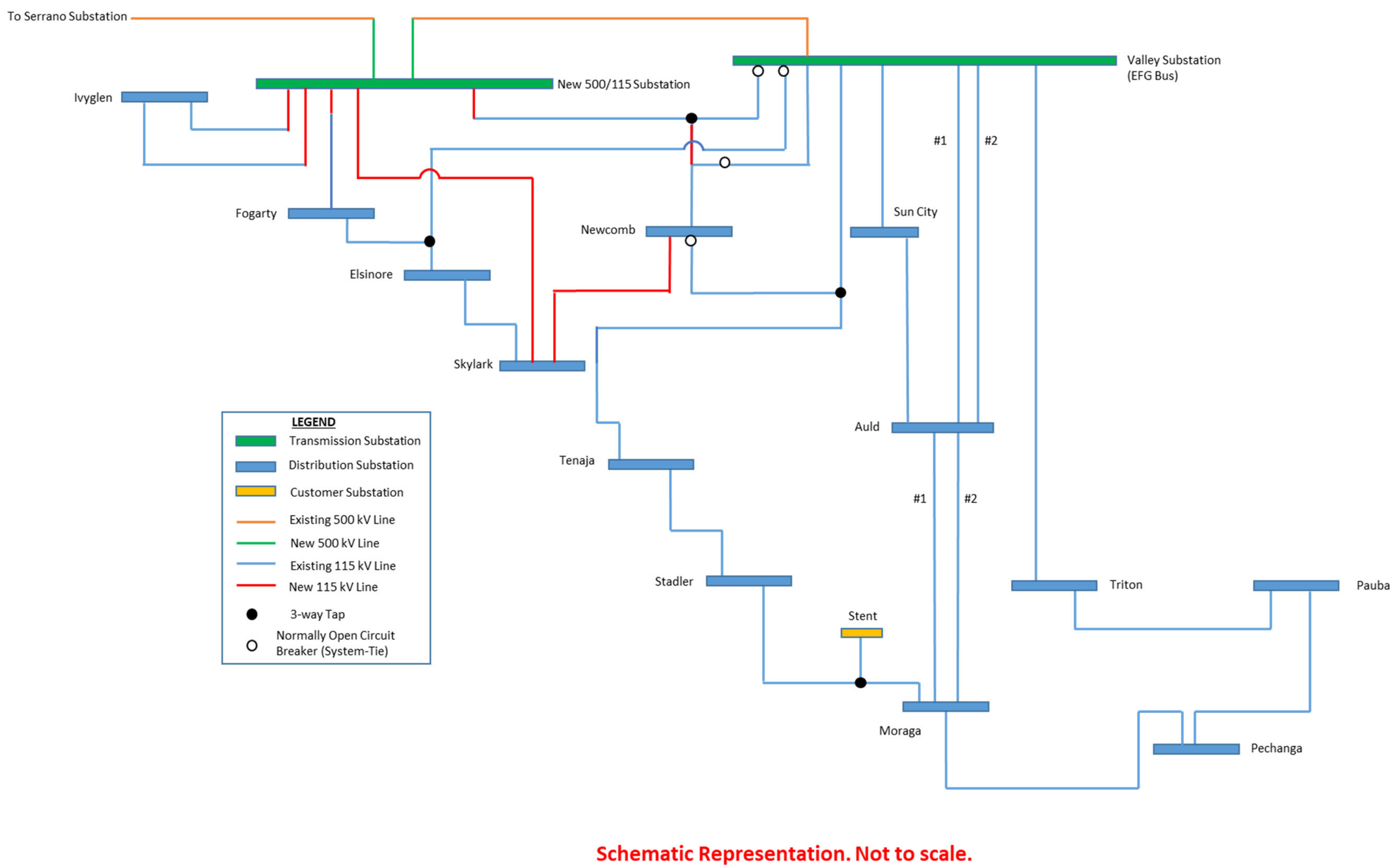

Figure C-1. System One-Line Schematic of the ASP

C.1.3 **Siting and Routing Description**

This project would include the following components:

- Construct a new 500/115 (kV) substation (approximately 40-acre footprint)

- Construct two new 500 kV transmission line segments between the existing Serrano-Valley 500 kV transmission line and the new 500/115 kV substation (approximately 3 miles)

- Construct a new double-circuit 115 kV subtransmission line and modifications to existing lines between the new 500/115 kV substation and SCE's existing five 115/12 kV distribution substations: Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb (approximately 21 miles)

This project would require the construction of approximately 24 miles of new or modified 500 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided in the subsections that follow.

New 500/115 kV Substation

The ASP would include the construction of a new 500/115 kV substation on approximately 40 acres of a privately owned, 124-acre property. The parcel is located north of the I-15 and the intersection of Temescal Canyon Road and Concordia Ranch Road in unincorporated western Riverside County.

New 500 kV Transmission Lines

Two new 500 kV transmission lines would be constructed, connecting the new 500/115 kV substation to the existing Serrano-Valley 500 kV transmission line. This new 500 kV transmission line would begin at the new 500/115 kV substation approximately 0.2 miles northeast of the corner of the intersection of Temescal Canyon Road and Concordia Ranch Road. The lines would leave the substation on new structures extending to the northeast for approximately 1.5 miles. Both lines will connect and be configured into the existing Serrano-Valley 500 kV transmission line.

New 115 kV Subtransmission Lines

New 115 kV subtransmission lines would be constructed, connecting the new 500/115 kV substation to SCE's existing five 115/12 kV substations (Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb substations). The lines would depart the new 500/115 kV substation on new structures and would intersect with existing 115 kV lines along Temescal Canyon Road and Concordia Ranch Road. A second 115 kV circuit would be installed on existing structures along Concordia Ranch Road, to the corner of Collier Avenue and Third Street in the City of Lake Elsinore. Along Third Street, new double-circuit structures would be installed from Collier Avenue to Second Street, and would be terminated to an existing, idle 115 kV line located on the north side of Interstate 15. Existing 115 kV structures would be replaced with double-circuit structures from East Flint Street and East Hill Street to Skylark Substation, and from Skylark Substation to the intersection of Bundy Canyon Road and Murrieta Road. At this intersection, a new single-circuit 115 kV line would be constructed to Newcomb Substation.

C.1.4 Siting and Routing Map

A siting and routing map of the ASP is provided in Figure C-2 on the following page.

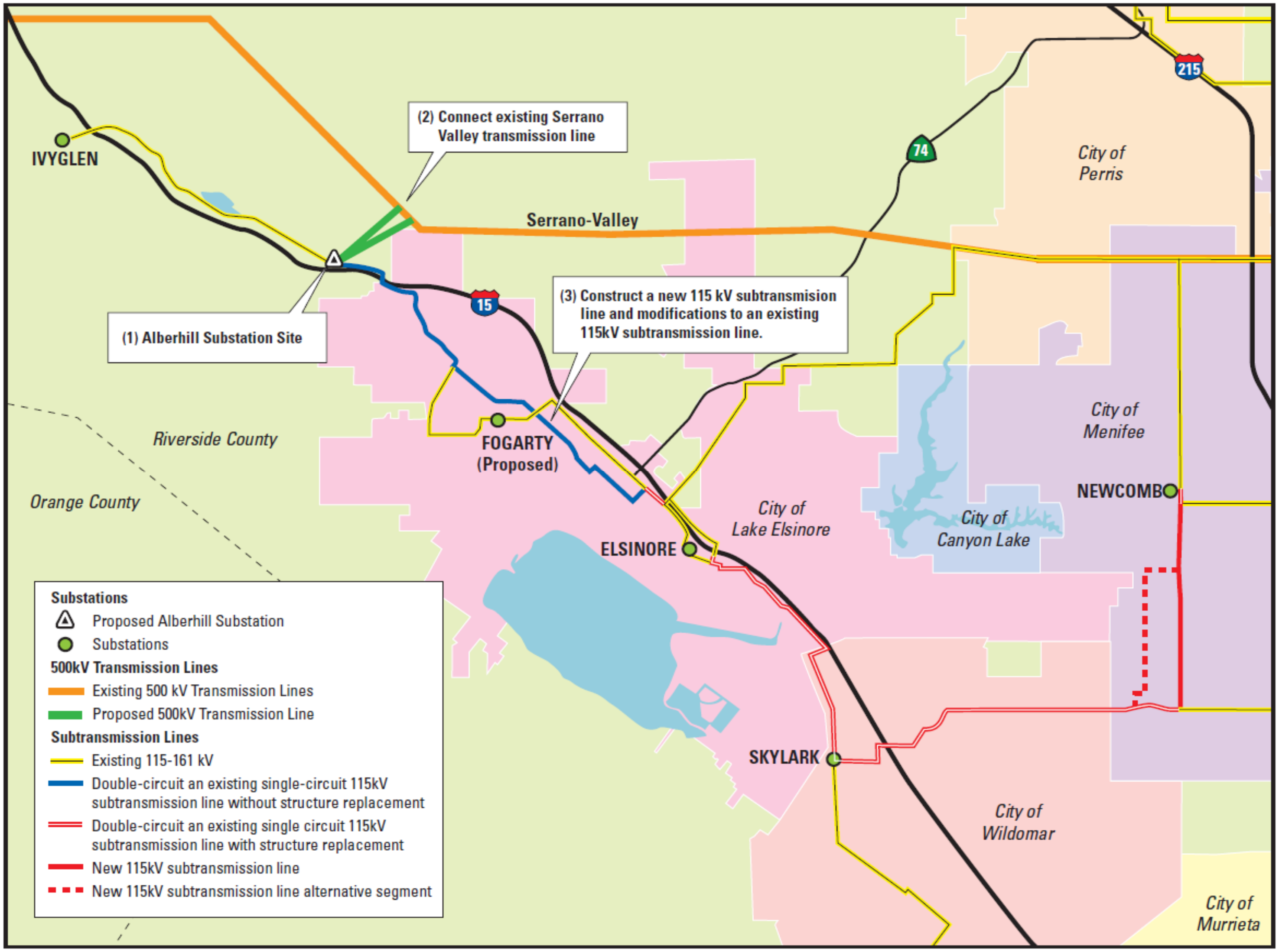

Figure C-2. Siting and Routing Map for the ASP

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C.1.5 **Project Implementation Scope**

Table C-1 summarizes the scope for this project.

Table C-1. ASP Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 500/115 kV Station	
Electrical	New (6) position, (4) element 500 kV breaker-and-a-half switchrack to accommodate (2) transformers & (2) lines
	(2) 560 MVA, 500/115 kV transformers
	New (9) position, (7) element 115 kV breaker-and-a-half switchrack to accommodate (2) transformers & (5) lines
	500 ad 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecommunications IT	(1) Mechanical Electrical Equipment Room (MEER) & (1) Microwave Tower
New 500 kV Transmission Line	
Loop-in Serrano-Valley 500 kV Line into New 500/115 kV Substation	3.3 miles overhead single-circuit
New 115 kV Subtransmission Lines	
New Substation to Valley, Ivyglen, Fogarty, Skylark, and Newcomb	11.3 miles overhead double-circuit, 3 miles overhead single-circuit, 6.3 miles overhead double-circuit existing
Support Scope Elements	
Substation Upgrades	
Serrano	(1) 500 kV line protection upgrade
Valley	(1) 500 kV & (1) 115 kV line protection upgrade
Fogarty	(1) 115 kV line protection upgrade
Skylark	(1) 115 kV line protection upgrade
Newcomb	(1) 115 kV line protection upgrade
Ivyglen	(2) 115 kV line protection upgrades
Elsinore	(1) 115 kV line protection upgrade
Distribution	
Station Light & Power – New Single-Circuit Underground	Approximately 900 feet
Replace Existing Underbuild	Approximately 20 miles
Transmission Telecom	
New Fiber Optic Line	8.7 miles (7.6 overhead, 1.11 underground) fiber optic cable
Real Properties	
500 kV Transmission Line	New Easement – (5) Parcels (2.3 miles, 200 ft. wide, 56.6 acres total)
115 kV Subtransmission Line	New Easement – (80) Parcels (27 miles, 10 ft. wide, 33 acres total)

Scope	Detailed Scope Element
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.1.6 Cost Estimate Detail

Table C-2 summarizes the costs for this project.

Table C-2. ASP Cost Table

Project Element	Cost ($M)
Licensing	27
Substation	215
Substation Estimate	196
Owners Agent (10% of construction)	19
Corporate Security	4
Bulk Transmission	53
Subtransmission	51
Transmission Telecom	0
Distribution	4
IT Telecom	7
RP	34
Environmental	28
Subtotal Direct Cost	**424**
Subtotal Battery Cost	**n/a**
Uncertainty	121
Total with Uncertainty	**545**
Total Capex	**545**
PVRR	**474**

C.2 SDG&E

C.2.1 System Solution Overview

The San Diego Gas and Electric (SDG&E) alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 230/115 kV system created at the southern boundary of the SCE service territory and adjacent to SDG&E's service territory. The new system would be provided power from the existing SDG&E 230 kV system via construction of a new 230/115 kV substation and looping in the SDG&E Escondido-Talega 230 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Pauba and Pechanga 115/12 kV distribution substations to the newly formed 230/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two 115 kV system-ties between the Valley South System and the newly formed 230/115 kV SDG&E-sourced system. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Pauba and Pechanga Substations) as well as additional load transfer from the Valley South System to the new system (Triton Substation) as needed.

C.2.2 System One-Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-3 on the following page.

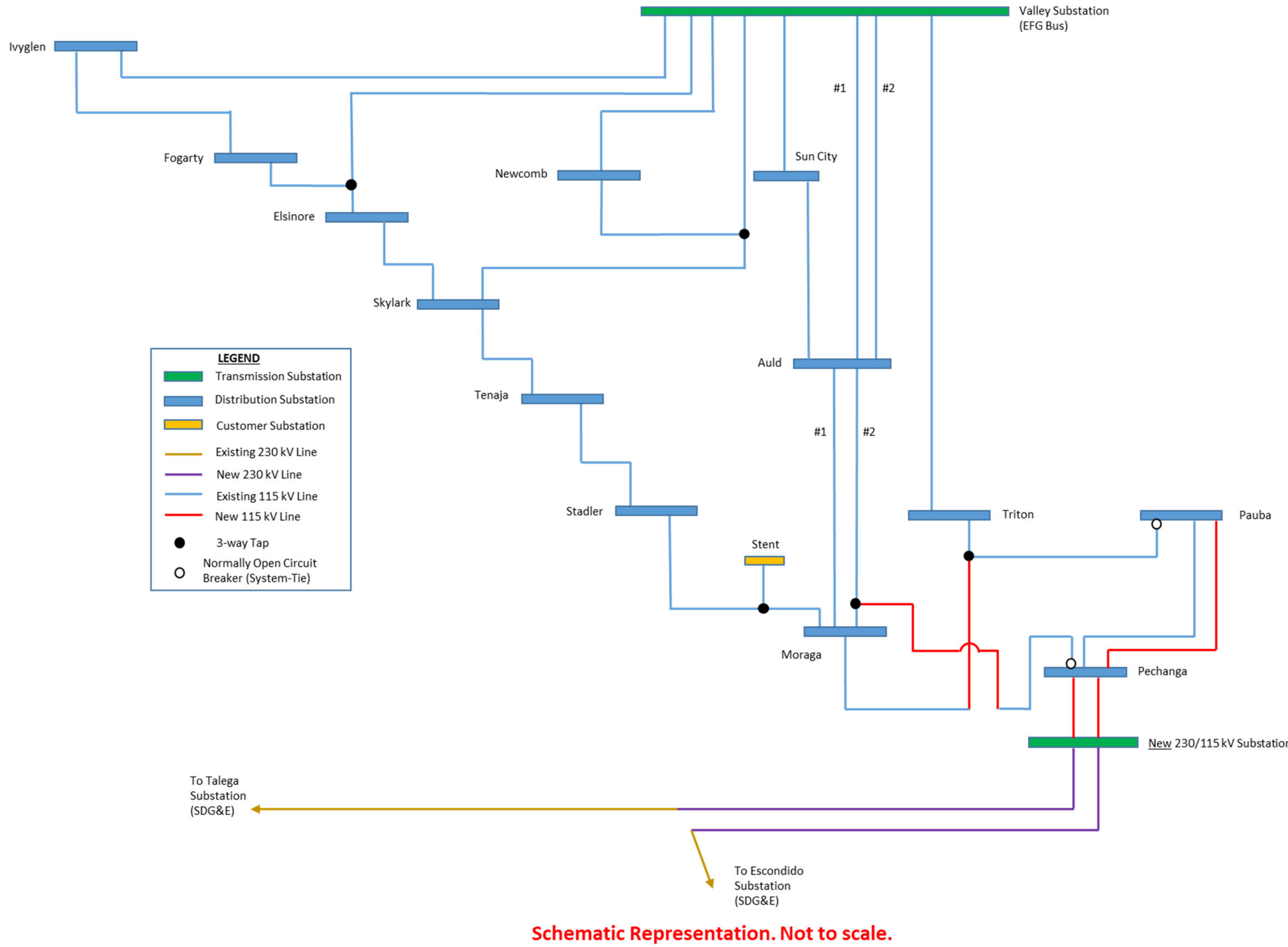

Figure C-3. System One-Line Schematic of the SDG&E Alternative

C.2.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 230/115 kV substation (approximately 15-acre footprint)
- Construct a new 230 kV double-circuit transmission line segment between SDG&E's existing Escondido-Talega 230 kV transmission line and SCE's new 230/115 kV substation (approximately 7.2 miles)
- Construct a new 115 kV double-circuit subtransmission line between SCE's new 230/115 kV substation and SCE's existing Pechanga Substation (approximately 2 miles)
- Demolish SCE's existing 115 kV switchrack at Pechanga Substation and reconstruct it on an adjacent parcel (approximately 3.2-acre footprint)
- Double-circuit SCE's existing Pauba-Pechanga 115 kV subtransmission line (approximately 7.5 miles)
- Double-circuit a segment of SCE's existing Auld-Moraga #2 115 kV subtransmission line (approximately 0.3 mile)

This system alternative would require the construction of approximately 9.2 miles of new 230 kV transmission and 115 kV subtransmission lines and the modification of approximately 7.8 miles of existing 115 kV subtransmission line. This system alternative totals approximately 17 miles of line construction. A detailed description of each of these components is provided in the subsections that follow.

New 230/115 kV Substation

The SDG&E alternative would include the construction of a new, approximately 15-acre, 230/115 kV substation on a privately owned, approximately 56-acre, vacant parcel. The parcel is located north of Highway 79, between the intersections with Los Caballos Road and Pauba Road, in southwestern Riverside County. The parcel is trapezoidal in shape and is bounded by residences and equestrian facilities to the north, east, and west; and Highway 79 and vacant land to the south. SCE may establish vehicular access to the site from Los Corralitos Road or Highway 79.

New 230 kV Double-Circuit Transmission Line

A new 230 kV double-circuit transmission line would be constructed, connecting the new 230/115 kV substation to SDG&E's existing Escondido-Talega 230 kV transmission line. This new 230 kV transmission line would begin at SDG&E's existing 230 kV Escondido-Talega 230 kV transmission line approximately 0.6 miles northeast of the intersection of Rainbow Heights Road and Anderson Road in the community of Rainbow in San Diego County. The line would leave the interconnection with SDG&E's existing Escondido-Talega 230 kV transmission line on new structures extending to the northeast for approximately 0.8 miles. At this point, the new line would enter Riverside County and the Pechanga Indian Reservation for approximately 4 miles. The line would continue in a generally northeast direction for approximately 1 mile before exiting the Pechanga Indian Reservation[91] and continue until intersecting Highway 79. At the intersection with Highway 79, the new transmission line would extend northwest and parallel to Highway 79 for approximately 1 mile until reaching the new 230/115 kV substation. This segment of the system alternative would be approximately 7.2 miles in length.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line would be constructed to connect the new 230/115 kV substation to SCE's existing 115/12 kV Pechanga Substation. The line would depart the new 230/115 kV substation to the northwest on new structures for approximately 1.5 miles while traveling parallel to Highway 79. Near the intersection of Highway 79 and Anza Road, the line would transition to an underground configuration and continue along Highway 79 for approximately 0.5 miles until reaching SCE's existing 115 kV Pechanga Substation. This segment of the system alternative would be approximately 2 miles in length.

Demolish and Reconstruct an Existing 115 kV Switchrack

SCE currently operates the existing 115 kV Pechanga Substation, located on an approximately 3.2-acre, SCE-owned parcel approximately 0.2 miles northeast of the intersection of Highway 79 and Horizon View Street. This site is bounded by vacant land to the east and west and residential uses to the north and south. SCE would demolish this existing 115 kV switchrack and reconstruct it on an approximately 16.9-acre, privately owned parcel directly east of the existing substation. The new 115 kV switchrack would occupy approximately 3.2 acres within the parcel.

Double-Circuit Existing 115 kV Subtransmission Lines

Pauba-Pechanga

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Pauba and Pechanga Substations in southwestern Riverside County. This existing line would be converted to a double-circuit configuration, adding a new 115 kV circuit between SCE's existing 115 kV Pauba and Pechanga Substations. The existing line departs SCE's existing 115 kV Pechanga Substation and extends east along Highway 79 until reaching Anza Road. At the intersection of Highway 79 and Anza Road, the line extends northeast along Anza Road until reaching De Portola Road. At this intersection, the line extends generally northeast along De Portola Road until intersecting Monte de Oro Road, then the line extends west along Monte de Oro Road until reaching Rancho California Road. At this point, the line extends south

[91] Approximately 0.5 miles of this segment of the line would be located outside of the Pechanga Reservation.

along Rancho California Road and terminates at SCE's existing 115 kV Pauba Substation. This segment of the system alternative is approximately 7.5 miles in length.

Auld-Moraga #2

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Auld Substation in the City of Murrieta and SCE's existing 115 kV Moraga Substation in the City of Temecula. An approximately 0.3-miles segment of this line within the City of Temecula would be converted from a single-circuit to double-circuit configuration. This segment would begin near the intersection of Rancho California Road and Calle Aragon. The existing line then extends south before turning west and intersecting Margarita Road, approximately 0.2 miles northwest of Rancho Vista Road.

C.2.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-4 on the following page.

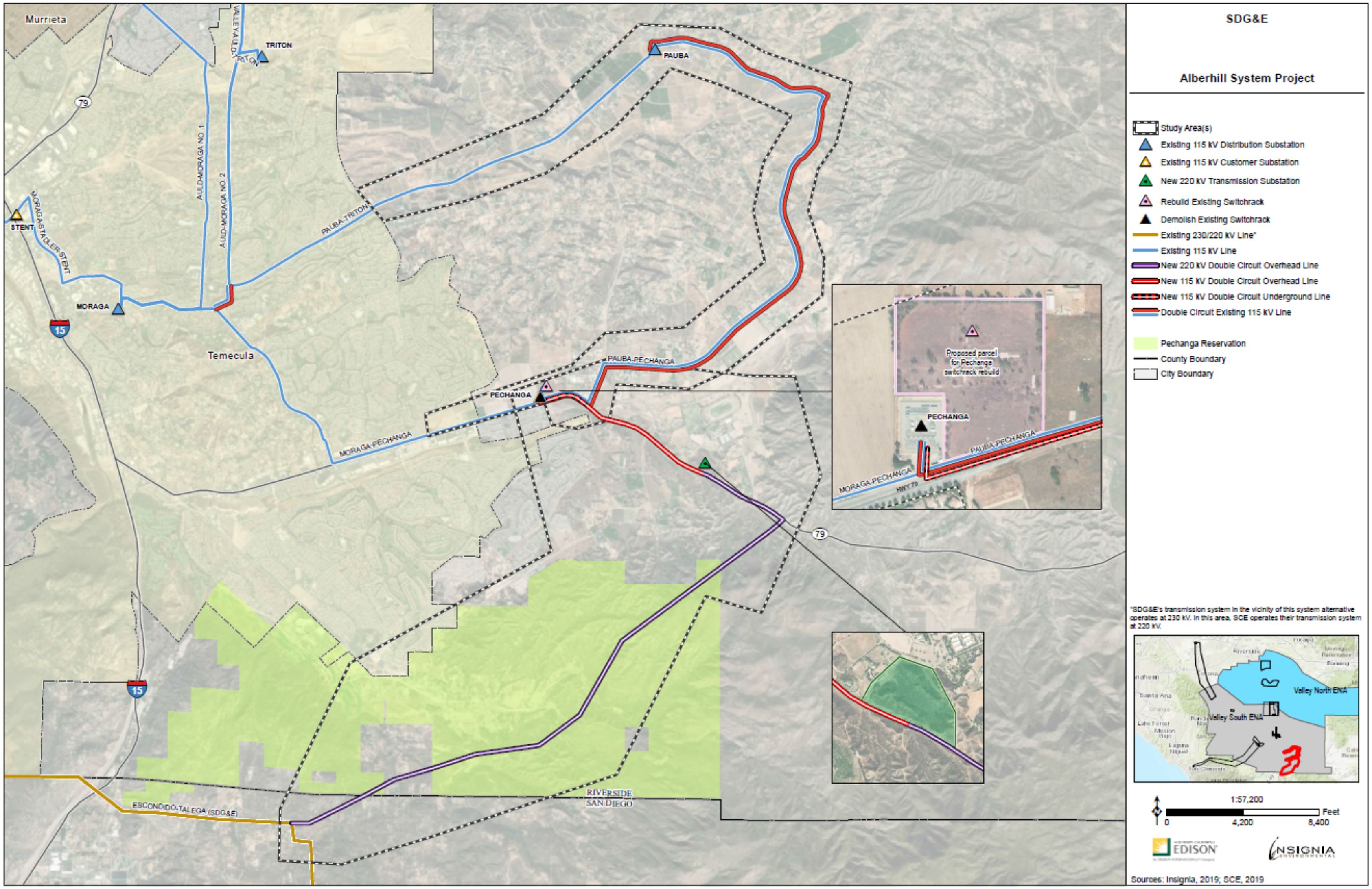

Figure C-4. Sitting and Routing Map for the SDG&E Alternative

C.2.5 **Project Implementation Scope**

Table C-3 summarizes the scope for this alternative.

Table C-3. SDG&E Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 230/115 kV Substation	
Electrical	New (3) position, (4) element 230 kV breaker-and-a-half switchrack to accommodate (2) banks & (2) lines
	(2) 280 MVA, 230/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	230 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 230 kV Transmission Line	
Loop-in SDG&E Escondido-Talega 230 kV line into New 230/115 kV Substation	7.3 miles overhead double-circuit 230 kV line
New 115 kV Subtransmission Line	
New 230/115 kV Substation to Pechanga Substation	2 miles (1.4 overhead double-circuit, 0.6 underground double-circuit)
Pauba-Pechanga	7.5 miles overhead double-circuit existing
Moraga-Pauba-Triton	0.3 miles overhead double-circuit existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Escondido	(1) 230 kV line protection upgrade
Moraga	(1) 115 kV line protection upgrade
Pechanga	
Civil	Demo the existing 115 kV switchrack
	Extend existing perimeter fence with a guardian 5000 fence
Electrical	New (6) position, (8) element 115 kV BAAH switchrack to accommodate (3) transformers & (5) lines
	New 115 kV line protection. Replace bank protection.
	HMI upgrade
Talega	(1) 230 kV line protection upgrade
Triton	(1) 115 kV line protection upgrade
Pauba	Equip (1) 115 kV line position; (1) 115 kV line protection upgrade

Scope	Detailed Scope Element
Distribution	
Station Light & Power – New Single-Circuit Underground	Approximately 3,300 feet
Replace Existing Single-Circuit Underbuild	Approximately 24,200 feet
Replace Existing Double-Circuit Underbuild	Approximately 17,200 feet
Transmission Telecom	
SDG&E Escondido-Talega 230 kV line to New 230/115 Substation	7.3 miles overhead fiber optic cable
New 230/115 kV Substation to Pechanga Substation	2 miles (1.4 miles overhead, 0.6 miles underground) fiber optic cable
Pauba-Pechanga	7.5 miles overhead fiber optic cable
Moraga-Pauba-Triton	0.3 miles overhead fiber optic cable
Real Properties	
SDG&E Substation A-A-04	Fee Acquisition – (1) 11.01-Acre Parcel
Pechanga Substation B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
SDG&E 230 kV Transmission Line	New Easement – (10) Parcels (2.5 miles, 100 ft. wide, 30.3 acres total)
SDG&E 115 kV Subtransmission Line	New Easement – (6) Parcels (2 miles, 30 ft. wide, 7.3 acres total)
Pauba-Pechanga 115 kV Subtransmission Line	New Easement – (9) Parcels (1.5 miles, 30 ft. wide, 5.5 acres total)
Auld-Moraga #2 115 kV Subtransmission Line	New Easement – (4) Parcels (0.33 miles, 30 ft. wide, 1.2 acres total)
SDG&E Laydown Yards	Lease – (2) 15-Acre Parcels for 96 months
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 230/115 kV Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.2.6 **Cost Estimate Detail**

Table C-4 summarizes the costs for this alternative.

Table C-4. SDG&E Cost Table

Project Element	**Cost ($M)**
Licensing	31
Substation	99
Substation Estimate	82
Owners Agent (10% of construction)	16
Corporate Security	3
Bulk Transmission	112
Subtransmission	42
Transmission Telecom	3
Distribution	6
IT Telecom	4
RP	20
Environmental	40
Subtotal Direct Cost	**359**
Subtotal Battery Cost	**n/a**
Uncertainty	181
Total with Uncertainty	**540**
Total Capex	**540**
PVRR	**453**

C.3 SCE Orange County

C.3.1 **System Solution Overview**

The SCE Orange County alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system via construction of a new 220/115 kV substation and looping in the SONGS-Viejo 220 kV line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Stadler and Tenaja 115/12 kV distribution substations to the newly formed 220/115 system. The existing 115 kV subtransmission lines serving Stadler and Tenaja substations would become two system-ties between the new 220/115 kV system and the Valley South System. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Stadler and Tenaja Substations) as well as additional load transfer from the Valley South System to the new system (Skylark or Moraga Substation) as needed.

C.3.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-5 on the following page.

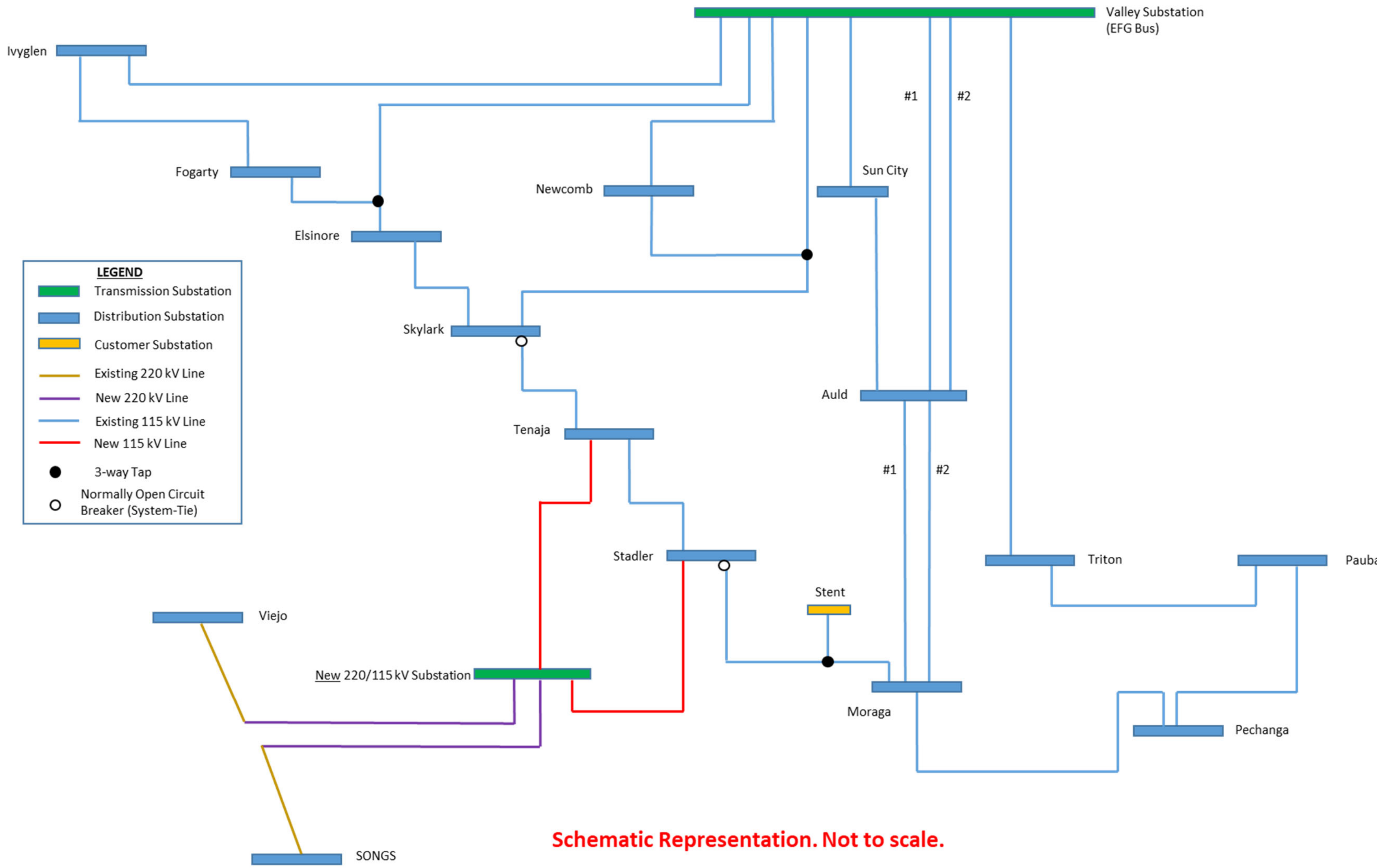

Figure C-5. System One-Line Schematic of the SCE Orange County Alternative

C.3.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 220/115 kV substation (approximately 15-acre footprint)
- Construct a new 220 kV double-circuit transmission line segment between SCE's existing San Onofre-Viejo 220 kV transmission line and SCE's new 220/115 kV substation (approximately 22.6 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Tenaja Substation (approximately 5 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Stadler Substation (approximately 2.6 miles)

In total, this system alternative would require the construction of approximately 30.2 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided in the subsections that follow

New 220/115 kV Substation

The SCE Orange County system alternative would involve the construction of a new, approximately 15-acre, 220/115 kV substation on a privately owned, approximately 67.3-acre, vacant parcel. The parcel is located southeast of Tenaja Road in the City of Murrieta. The parcel is generally trapezoidal in shape and surrounded by hilly, undeveloped land to the south and generally flat, undeveloped land to the north. SCE may establish vehicular access to this site from Tenaja Road, which is currently an unpaved road.

New 220 kV Double-Circuit Transmission Line

A new 220 kV double-circuit transmission line would be constructed, connecting the new 220/115 kV substation to SCE's existing San Onofre-Viejo 220 kV transmission line. This new 220 kV transmission line would begin at the existing San Onofre-Viejo 220 kV transmission line approximately 0.2 miles southwest of the intersection of East Avenida Pico and Camino la Pedriza in the City of San Clemente in Orange County. The line would leave the interconnection with the San Onofre-Viejo 220 kV transmission line on new structures to the east for approximately 3.2 miles. At this point, the new line would enter San Diego County, generally paralleling Talega Road and SDG&E's existing Escondido-Talega 220 kV transmission line for approximately 3.1 miles,[92] reaching the intersection of Talega Road and Indian Potrero Truck Trail. The line would then extend southeast, briefly crossing Cleveland National Forest, then extending east generally parallel to SDG&E's existing Escondido-Talega 220 kV transmission line for approximately 2.2 miles. The line would continue east, crossing Cleveland National Forest for approximately 5.5 miles, then turn to the northeast for approximately 1.9 miles before entering Riverside County. At this point, the line would extend generally northeast until reaching the new 220/115 kV substation site. Approximately 4.7 miles of this portion of the route would

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[92] Approximately 0.4 miles of this portion of the line would cross back into Orange County.

cross the Santa Rosa Plateau Ecological Preserve. This segment of the system alternative would total approximately 22.6 miles.

New 115 kV Single-Circuit Subtransmission Lines

New Substation to Tenaja Substation

A new 115 kV single-circuit subtransmission line would be constructed, connecting the new 220/115 kV substation to SCE's existing 115 kV Tenaja Substation. The line would begin at the proposed new substation site in the City of Murrieta and extend generally north on new structures until intersecting Tenaja Road. At this point, the line would extend northeast along Tenaja Road, Vineyard Parkway, and Lemon Street until intersecting SCE's existing Stadler-Tenaja 115 kV subtransmission line at Adams Avenue. At this point, the new 115 kV subtransmission line and Stadler-Tenaja 115 kV subtransmission line would be co-located on a single set of structures until reaching SCE's existing 115 kV Tenaja Substation. The existing line travels generally northwest along Adams Avenue, southwest on Nutmeg Street, and then continues in a northwest direction along Washington Avenue. At the end of Washington Avenue, the route enters the City of Wildomar and continues northwest along Palomar Street until reaching Clinton Keith Road. At the intersection with Clinton Keith Road, the route travels south until terminating at SCE's existing 115 kV Tenaja Substation. This segment of the system alternative would be approximately 5 miles in length.

New Substation to Stadler Substation

A new 115 kV single-circuit subtransmission line would be constructed, connecting the new 220/115 kV substation site to SCE's existing 115 kV Stadler Substation. The line would begin at the proposed new substation site in the City of Murrieta and extend northeast for approximately 0.1 miles on new structures. At this point, the line would extend southeast, crossing the Santa Rosa Plateau Ecological Preserve for approximately 0.6 mile. The line would extend northeast, leaving the Santa Rosa Plateau Ecological Preserve, and paralleling Ivy Street until the intersection with Jefferson Avenue. At this intersection, the new 115 kV subtransmission line would be co-located on a single set of structures with SCE's existing Stadler-Tenaja 115 kV subtransmission line for approximately 0.2 miles along Los Alamos Road until terminating at SCE's existing 115 kV Stadler Substation. This segment of the system alternative would be approximately 2.6 miles in length.

C.3.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-6 on the following page.

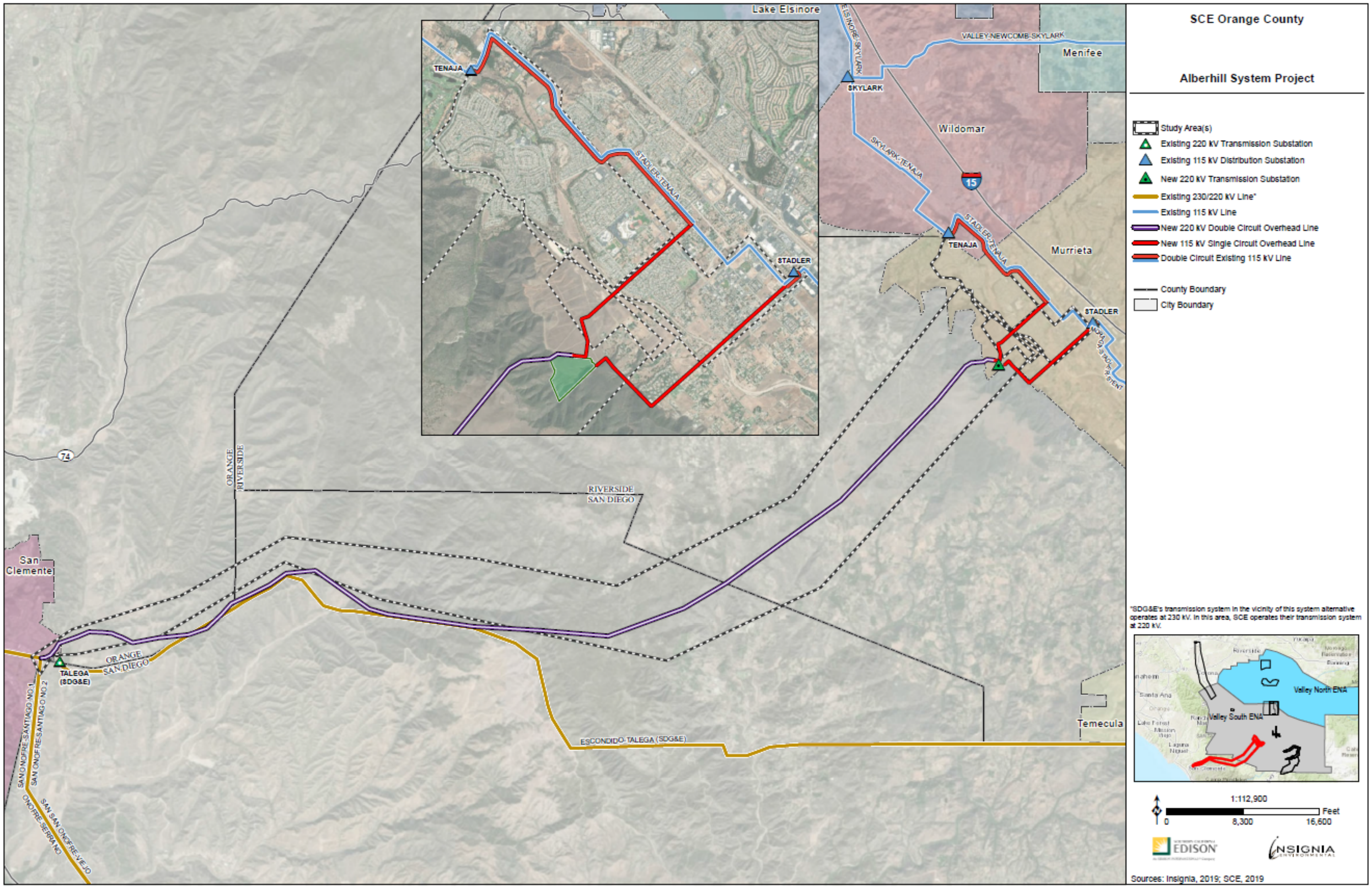


Figure C-6. Siting and Routing Map for the SCE Orange County Alternative

C.3.5 **Project Implementation Scope**

Table C-5 summarizes the scope for this alternative.

Table C-5. SCE Orange County Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 220/115 kV Station	
Electrical	New (3) position, (4) element 220 kV breaker-and-a-half switchrack to accommodate (2) transformers & (2) lines
	(2) 280 MVA, 220/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	220 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 220 kV Transmission Line	
Loop-in SONGS-Viejo 220 kV Line to New 220/115 kV Substation	22.6 miles overhead double-circuit
New 115 kV Subtransmission Lines	
New 220/115 kV Substation to Stadler Substation	2.6 miles (2.4 overhead single-circuit, 0.2 overhead double-circuit existing)
New 220/115 kV Substation to Tenaja Substation	5 miles (1.8 overhead single-circuit, 3.1 overhead double-circuit existing)
Support Scope Elements	
Substation Upgrades	
SONGS	(1) 220 kV line protection upgrade
Stadler	Remove No. 5 cap bank and convert to (1) 115 kV line position
Viejo	(1) 220 kV line protection upgrade
Tenaja	Equip (1) 115 kV Position
Distribution	
Station Light & Power – New Single-Circuit Underground	Approximately 4,800 feet
Replace Existing Double-Circuit Underbuild	Approximately 16,800 feet
Replace Existing Single-Circuit Overhead	Approximately 7,400 feet
Replace Existing Double-Circuit Overhead	Approximately 4,000 feet
Transmission Telecom	
SONGS Viejo to New 220/115 kV Sub	22.6 miles overhead fiber optic cable
New Substation to Stadler Substation	2.6 miles overhead fiber optic cable
New Substation to Tenaja Substation	5 miles overhead fiber optic cable

Scope	Detailed Scope Element
Real Properties	
Orange County Substation	Fee Acquisition – (1) 66.33-Acre Parcel
SONGS-Viejo 220 kV Transmission Line	New Easement – (75) Parcels (25 miles, 100 ft. wide, 303.03 acres total)
SONGS-Viejo 220 kV Transmission Line	Government Lands – (3) Parcels
Stadler 115 kV Subtransmission Line	New Easement – (10) Parcels, (0.5 miles, 30 ft. wide, 1.8 acres total)
Tenaja 115 kV Subtransmission Line	New Easement – (10) Parcels, (1.5 miles, 30 ft. wide, 5.5 acres total)
SCE OC Laydown Yards	Lease – (2) 15-Acre Parcels for 110 months
Environmental	
All new Substation/Transmission/Subtransmission Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 220/115 kV Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.3.6 **Cost Estimate Detail**

Table C-6 summarizes the costs for this alternative.

Table C-6. SCE Orange County Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	90
Substation Estimate	60
Owners Agent (10% of construction)	30
Corporate Security	3
Bulk Transmission	347
Subtransmission	25
Transmission Telecom	5
Distribution	6
IT Telecom	3
RP	63
Environmental	65
Subtotal Direct Cost	**637**
Subtotal Battery Cost	**n/a**
Uncertainty	314
Total with Uncertainty	**951**
Total Capex	**951**
PVRR	**748**

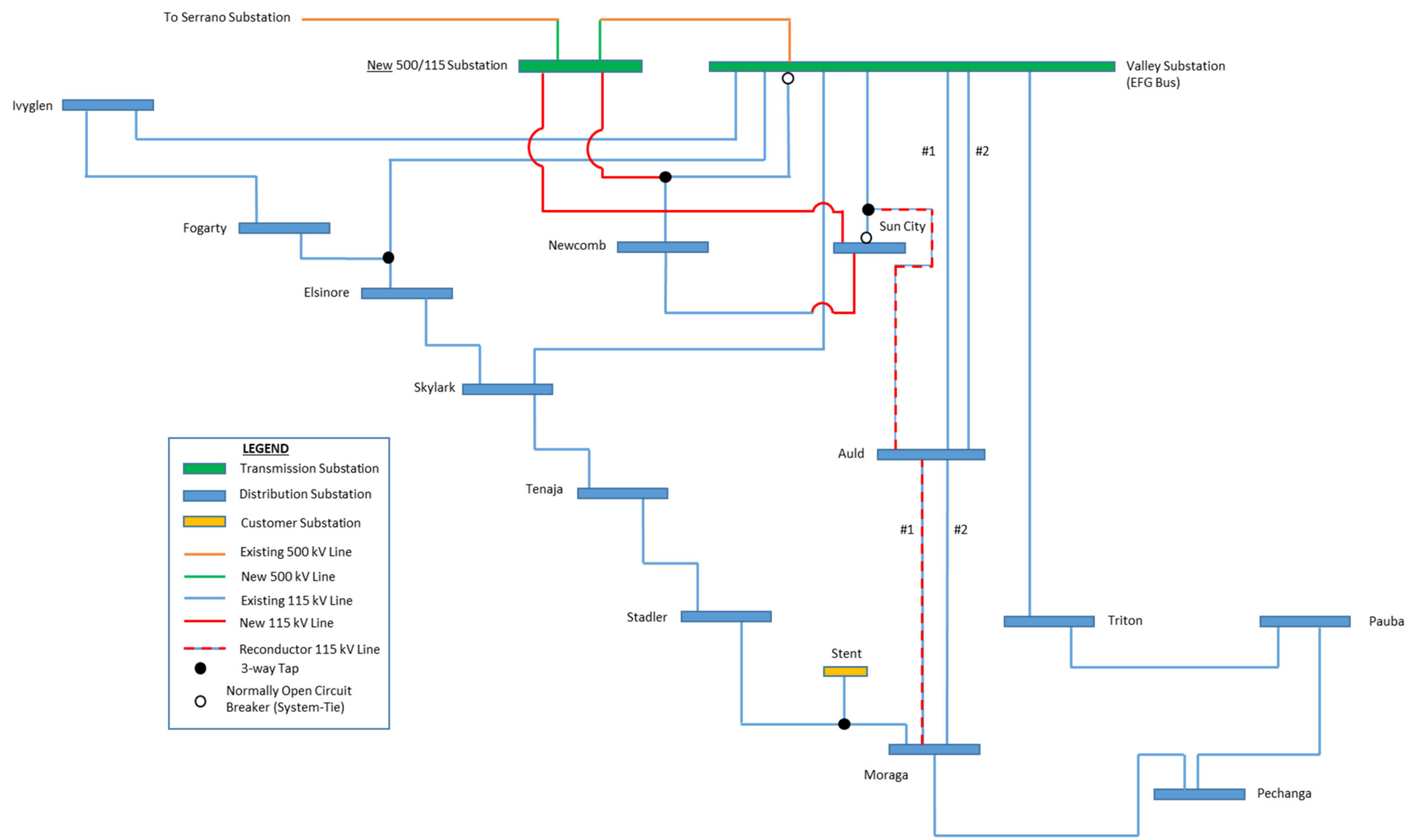
C.4 Menifee

C.4.1 **System Solution Overview**

The Menifee alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 500/115 kV system via construction of a new 500/115 kV substation and looping in the Serrano-Valley 500 kV transmission line. This alternative includes 115 kV subtransmission line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the newly formed 500/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two system-ties between the Valley South System and the newly formed 500/115 kV Menifee System. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the new system (Auld Substation) as needed.

C.4.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-7 on the following page.



Schematic Representation. Not to scale.

Figure C-7. System One-Line Schematic of the Menifee Alternative

C.4.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 500/115 kV substation (approximately 15-acre footprint)
- Construct a new 500 kV double-circuit transmission line to loop SCE's existing Serrano-Valley 500 kV transmission line into the new 500/115 kV substation (0.1 mile)
- Construct a new 115 kV single-circuit subtransmission line between the new 500/115 kV substation and SCE's existing 115 kV Sun City Substation (approximately 4.6 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to the new 500/115 kV substation (approximately 0.1 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Sun City 115 kV subtransmission line (approximately 7.7 miles)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)

This system alternative would require the construction of approximately 5.5 miles of new 500 kV transmission and 115 kV subtransmission lines and the modification of approximately 7.714.9 miles of existing 115 kV subtransmission line. This system alternative totals approximately 20.4 miles. A detailed description of each of these components is provided in the subsections that follow.

<u>New 500/115 kV Substation</u>

The Menifee system alternative would involve the construction of a new, approximately 15-acre, 500/115 kV substation on six privately owned vacant parcels, totaling approximately 23.7 acres. The parcels are located south of Matthews Road, north of McLaughlin Road, west of Palomar Road, and east of San Jacinto Road in the City of Menifee. The parcels are also located directly east of the Inland Empire Energy Center (IEEC). When combined, the parcels form a trapezoid shape and are surrounded by industrial uses and vacant lands to the north and east, SCE's existing transmission line corridor to the south, and the IEEC to the west. SCE may establish vehicular access to this site from Matthews Road, Palomar Road, and/or San Jacinto Road.

<u>New 500 kV Double-Circuit Transmission Line</u>

A new overhead 500 kV double-circuit transmission line segment would be constructed to loop SCE's existing Serrano-Valley 500 kV transmission line into the new 500/115 kV substation in the City of Menifee. This route would begin within SCE's existing transmission corridor along McLaughlin Road and approximately 0.1 miles west of the intersection of McLaughlin Road and

Palomar Road before extending north until reaching the new 500/115 kV substation. This segment of the system alternative would be approximately 0.1 miles in length.

New 115 kV Single-Circuit Subtransmission Lines

New Substation to Sun City Substation

A new 115 kV single-circuit subtransmission line would be constructed, connecting the new 500/115 kV substation to SCE's existing 115 kV Sun City Substation in the City of Menifee. The line would exit the new 500/115 kV substation's southeast corner and extend south along Palomar Road, crossing under SCE's existing transmission line corridor for approximately 0.3 mile. At this point, the route would extend generally southeast until reaching Rouse Road. The line would extend east along Rouse Road until the intersection with Menifee Road, then the line would transition to an underground configuration and extend south along Menifee Road for approximately 3 miles until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east for approximately 0.5 mile, parallel to the Auld-Sun City 115 kV subtransmission line, until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.6 miles in length.

Valley-Newcomb to New Substation

A new underground 115 kV subtransmission line segment would be constructed to re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to the new 500/115 kV substation in the City of Menifee. This route would begin within SCE's existing transmission corridor along McLaughlin Road, which is approximately 0.1 miles west of the intersection of McLaughlin Road and Palomar Road, and extend north until reaching the new 500/115 kV substation. This segment of the system alternative would be approximately 0.1 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld-Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet until reaching an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Reconductor Existing 115 kV Subtransmission Lines

Auld-Sun City

SCE's existing Auld-Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the City of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 7.7 miles in length.

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

C.4.4 Siting and Routing Map

A siting and routing map of this alternative is provided Figure C-8 the following page.

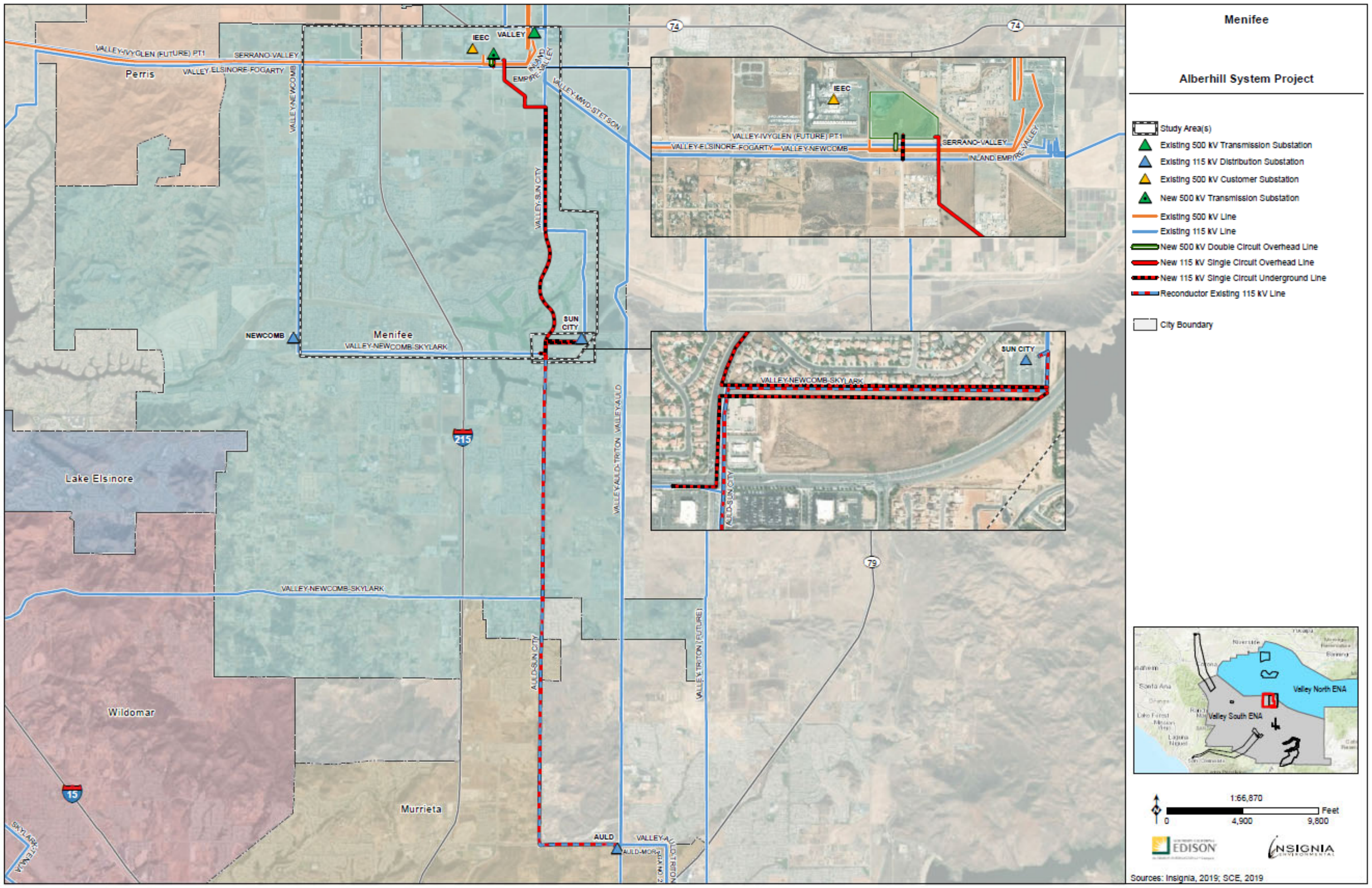


Figure C-8. Siting and Routing Map for the Menifee Alternative[93]

[93] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.4.5 Project Implementation Scope

Table C-7 summarizes the scope for this alternative.

Table C-7. Menifee Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 500/115 kV Substation	
Electrical	New (3) position, (4) element 500 kV breaker-and-a-half switchrack to accommodate (2) transformers and (2) lines
	(2) 280 MVA, 500/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	500 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 500 kV Transmission Line	
Loop-In of Serrano-Valley 500 kV Transmission Line to new 500/115 Substation	0.1 miles overhead double-circuit
New 115 kV Subtransmission Lines	
Menifee	4.8 miles (1.2 overhead single-circuit , 3.5 underground single-circuit)
Auld-Sun City	7.7 miles overhead reconductor existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Sun City-Newcomb	0.7 miles underground single-circuit
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Valley	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV position, repurpose position no. 2 for 115 kV line with (1) line protection upgrade, and (1) line protection upgrade
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 18,900 feet
Replace Existing Double-Circuit Overhead	1,400 feet
Transmission Telecom	
Menifee	4.8 miles (1.2 miles overhead, 3.5 miles underground) fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable

Scope	Detailed Scope Element
Real Properties	
Menifee	New Easement – (27) Parcels (1.5 miles, 30 ft. wide, 5.45 acres total)
Auld-Sun City	New Easement – (15) Parcels (2 miles, 30 ft. wide, 7.27 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 500/115 kV Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.4.6 **Cost Estimate Detail**

Table C-8 summarizes the costs for this alternative.

Table C-8. Menifee Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	105
Substation Estimate	93
Owners Agent (10% of construction)	12
Corporate Security	3
Bulk Transmission	4
Subtransmission	89
Transmission Telecom	3
Distribution	2
IT Telecom	5
RP	14
Environmental	24
Subtotal Direct Cost	**279**
Subtotal Battery Cost	**n/a**
Uncertainty	117
Total with Uncertainty	**396**
Total Capex	**396**
PVRR	**331**

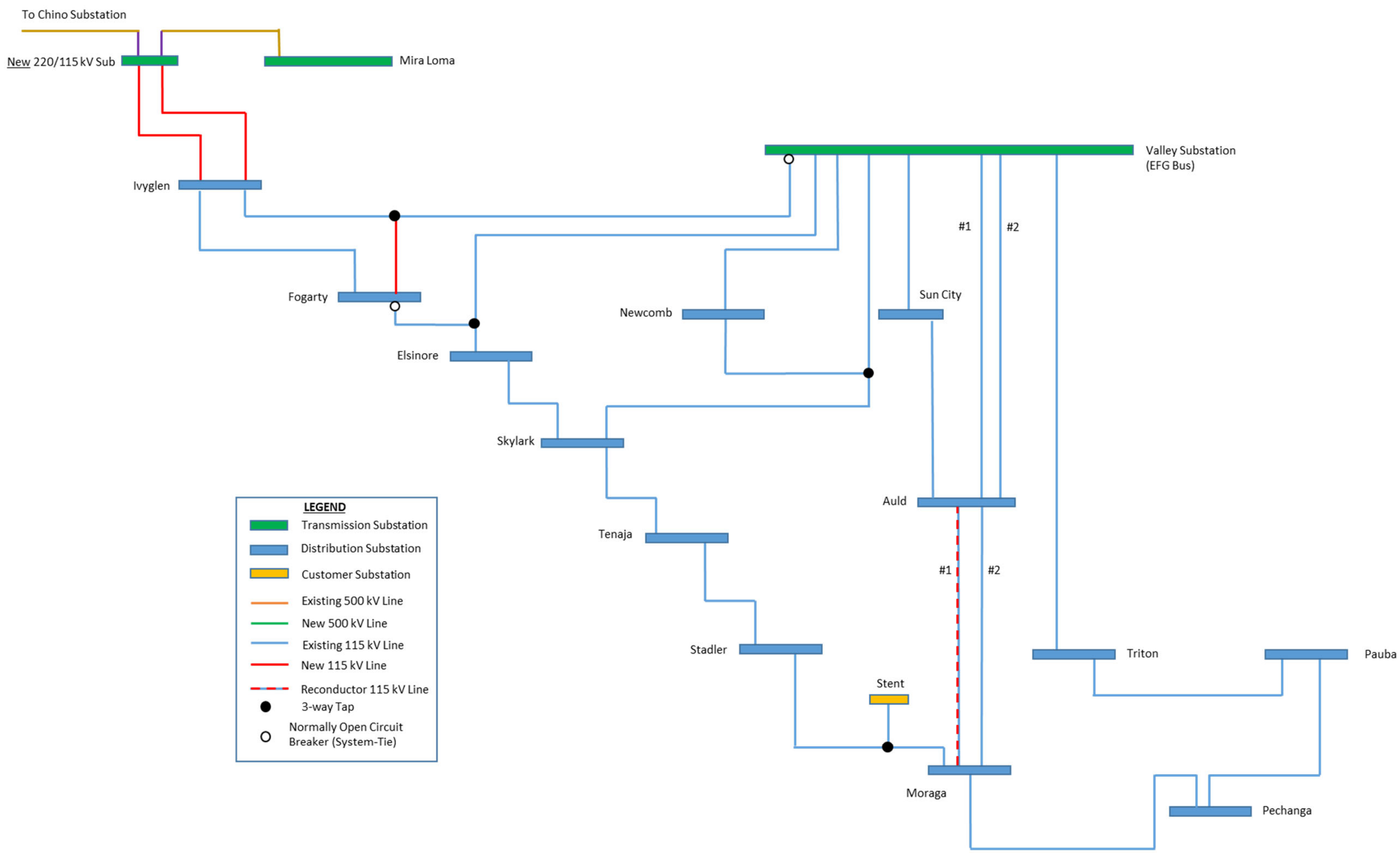
C.5 Mira Loma

C.5.1 **System Solution Overview**

The Mira Loma alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system via construction of a new 220/115 kV substation and looping in the Mira Loma-Chino 220 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Ivyglen and Fogarty 115/12 kV distribution substations to the new 220/115 kV system. The existing 115 kV subtransmission lines serving Ivyglen and Fogarty substations would become two system-ties between the newly formed 220/115 kV Mira Loma System and the Valley South System. The system-ties would allow for the transfer of load from the new system back to the Valley South System (either or both Ivyglen and Fogarty Substations) as well as additional load transfer from the Valley South System to the new system (Elsinore Substation) as needed.

C.5.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-9 on the following page



Schematic Representation. Not to scale.

Figure C-9. System One-Line Schematic of the Mira Loma Alternative

C.5.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 220/115 kV substation (approximately 15-acre footprint)
- Construct a new 220 kV double-circuit transmission line segment to loop SCE's existing Chino-Mira Loma 220 kV transmission line into SCE's new 220/115 kV substation (approximately 130 feet)
- Construct a new 115 kV double-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation (approximately 21.6 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to tap SCE's future Valley-Ivyglen 115 kV subtransmission line to SCE's existing 115 kV Fogarty Substation (approximately 0.6 mile)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)

In total, this system alternative would require the construction of approximately 29.4 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided in the subsections that follow.

New 220/115 kV Substation

The Mira Loma system alternative would involve the construction of a new, approximately 15-acre, 220/115 kV substation on a privately owned, approximately 27-acre, vacant parcel. The parcel is located north of Ontario Ranch Road, east of Haven Avenue, and west of Hamner Avenue in the City of Ontario. The parcel is rectangular in shape and is bounded by vacant land to the north, SCE's existing 220 kV Mira Loma Substation and vacant land to the east, vacant land to the south, and vacant land and industrial uses to the west. The vacant parcel has a residential land use designation, and an existing SCE transmission corridor crosses the southeast portion of the site. Vehicular access would likely be established from Ontario Ranch Road.

New 220 kV Double-Circuit Transmission Line

A new 220 kV double-circuit transmission line segment would be constructed between the existing Chino-Mira Loma 220 kV transmission line and SCE's new 220/115 kV substation. This approximately 130-foot segment would begin within SCE's existing transmission corridor and approximately 2,000 feet east of Haven Avenue and would extend south until reaching SCE's new 220/115 kV substation site.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line would be constructed, connecting SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation. This line would exit the new 220/115 kV substation site from the southerly portion of the property and travel east in an underground configuration along Ontario Ranch Road for approximately 0.2 mile. The line would pass under SCE's existing transmission line corridor and then transition to an overhead configuration, continuing on new structures along Ontario Ranch Road for approximately 0.5 miles until intersecting Hamner Road. The line would then extend south along Hamner Road and parallel to SCE's existing Mira Loma-Corona 66 kV subtransmission line for approximately 6.8 miles. Within this approximately 6.8-miles portion of the route, the line would exit the City of Ontario and enter the City of Eastvale at the intersection with Bellegrave Avenue. Within the City of Eastvale, the line would continue along Hamner Avenue, cross the Santa Ana River, and enter the City of Norco. Within the City of Norco, the line would continue south along Hamner Avenue until intersecting 1st Street. At this point, the line would extend west along 1st Street for approximately 0.5 miles until West Parkridge Avenue. At this intersection, the line would enter the City of Corona and continue generally south along North Lincoln Avenue for approximately 3.2 miles, paralleling the Chase-Corona-Databank 66 kV subtransmission line between Railroad Street and West Ontario Avenue. At the intersection with West Ontario Avenue, the line would extend east and continue to parallel SCE's existing Chase-Corona-Databank 66 kV subtransmission line for approximately 1.4 miles until the intersection with Magnolia Avenue. The line would continue to extend along West Ontario Avenue for approximately 0.2 mile, then parallel SCE's existing Chase-Jefferson 66 kV subtransmission line between Kellogg Avenue and Interstate (I-) 15 for approximately 1.7 miles. The line would continue along East Ontario Avenue, pass under I-15, and exit the City of Corona after approximately 0.2 miles at the intersection of East Ontario Avenue and State Street. The line would extend southeast along East Ontario Avenue within Riverside County for approximately 1.8 miles until the intersection of Cajalco Road. At this intersection, the line would extend southeast along Temescal Canyon Road, crossing the City of Corona for approximately 1.2 miles between Cajalco Road and Dos Lagos Drive. The line would then continue within Riverside County along Temescal Canyon Road for approximately 3.9 miles, crossing under I-15 and terminating at SCE's existing 115 kV Ivyglen Substation. This segment of the system alternative would be approximately 21.6 miles in length.

New 115 kV Single-Circuit Subtransmission Line

A new 115 kV single-circuit subtransmission line segment would be constructed to tap SCE's future Valley-Ivyglen 115 kV subtransmission line into SCE's existing 115 kV Fogarty Substation. The new line segment would begin along the future Valley-Ivyglen 115 kV subtransmission line's alignment, approximately 680 feet southeast of the intersection of Pierce Street and Baker Street in the City of Lake Elsinore. The new line segment would extend generally southwest and parallel to SCE's existing Valley-Elsinore-Fogarty 115 kV subtransmission line until terminating at SCE's existing 115 kV Fogarty Substation. This segment of the system alternative would be approximately 0.6 miles in length.

Reconductor Existing 115 kV Subtransmission Lines

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE’s existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

C.5.4 **Siting and Routing Map**

A siting and routing map of this alternative is provided in Figure C-10 on the following page.

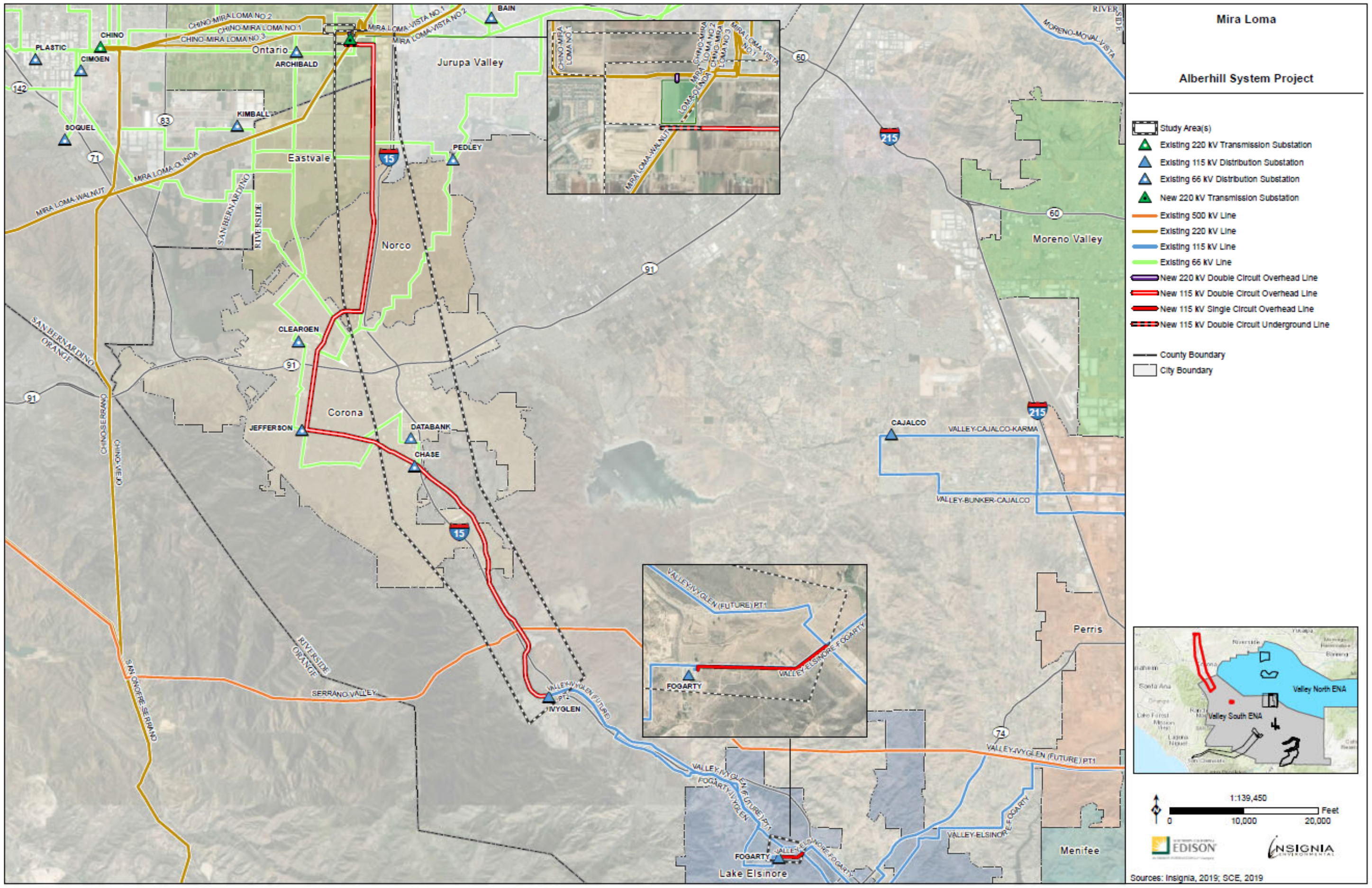


Figure C-10. Siting and Routing Map for the Mira Loma Alternative[94]

[94] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.5.5 **Project Implementation Scope**

Table C-9 summarizes the scope for this alternative.

Table C-9. Mira Loma Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 220/115 kV Station	
Electrical	New (3) position, (4) element 220 kV breaker-and-a-half switchrack to accommodate (2) transformers & (2) lines
	(2) 280 MVA, 220/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	220 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 220 kV Transmission Line	
Loop-in Chino-Mira Loma 220 kV Transmission Line to New 220/115 kV Substation	100 feet new overhead double-circuit
New 115 kV Subtransmission Lines	
Mira Loma-Ivyglen	21.6 miles (21.4 overhead double-circuit , 0.2 underground double-circuit)
Valley-Ivyglen to Fogarty	0.6 miles overhead single-circuit
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Mira Loma	(1) 220 kV line protection upgrade
Chino	(1) 220 kV line protection upgrade
Fogarty	Equip (1) 115 kV line position
Ivyglen	Remove No.3 capacitor from Position 1
	Equip (2) 115 kV line positions; (1) 115 kV line protection upgrade
Valley	(1) 115 kV line protection upgrade
Distribution	
Replace Existing Single-Circuit Overhead	Approximately 15,400 feet
Replace Existing Double-Circuit Overhead	Approximately 11,200 feet
Transmission Telecom	
Chino-Mira Loma 220 kV Line to New 220/115 Substation	100 feet overhead fiber optic cable
Mira Loma-Ivyglen	21.6 miles (21.4 overhead, 0.2 underground) fiber optic cable
Valley-Ivyglen to Fogarty	0.6 miles overhead fiber optic cable

Scope	Detailed Scope Element
Real Properties	
Mira Loma Substation D-C-02A	Fee Acquisition – (1) 26.78-Acre Parcel
Mira Loma-Ivyglen 115 kV Subtransmission Line	New Easement – (68) Parcels (10 miles, 30 ft. wide, 36.36 acres total)
Valley-Ivyglen to Fogarty 115 kV Subtransmission Line	New Easement – (10) Parcels (0.36 miles, 30 ft. wide, 1.31 acres total)
Mira Loma Laydown Yard	Lease – (1) 10-Acre Parcel for 92 months
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 220/115 kV Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.5.6 Cost Estimate Detail

Table C-10 summarizes the costs for this alternative.

Table C-10. Mira Loma Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	64
Substation Estimate	54
Owners Agent (10% of construction)	9
Corporate Security	3
Bulk Transmission	3
Subtransmission	97
Transmission Telecom	3
Distribution	4
IT Telecom	3
RP	22
Environmental	21
Subtotal Direct Cost	**243**
Subtotal Battery Cost	**n/a**
Uncertainty	113
Total with Uncertainty	**365**
Total Capex	**365**
PVRR	**309**

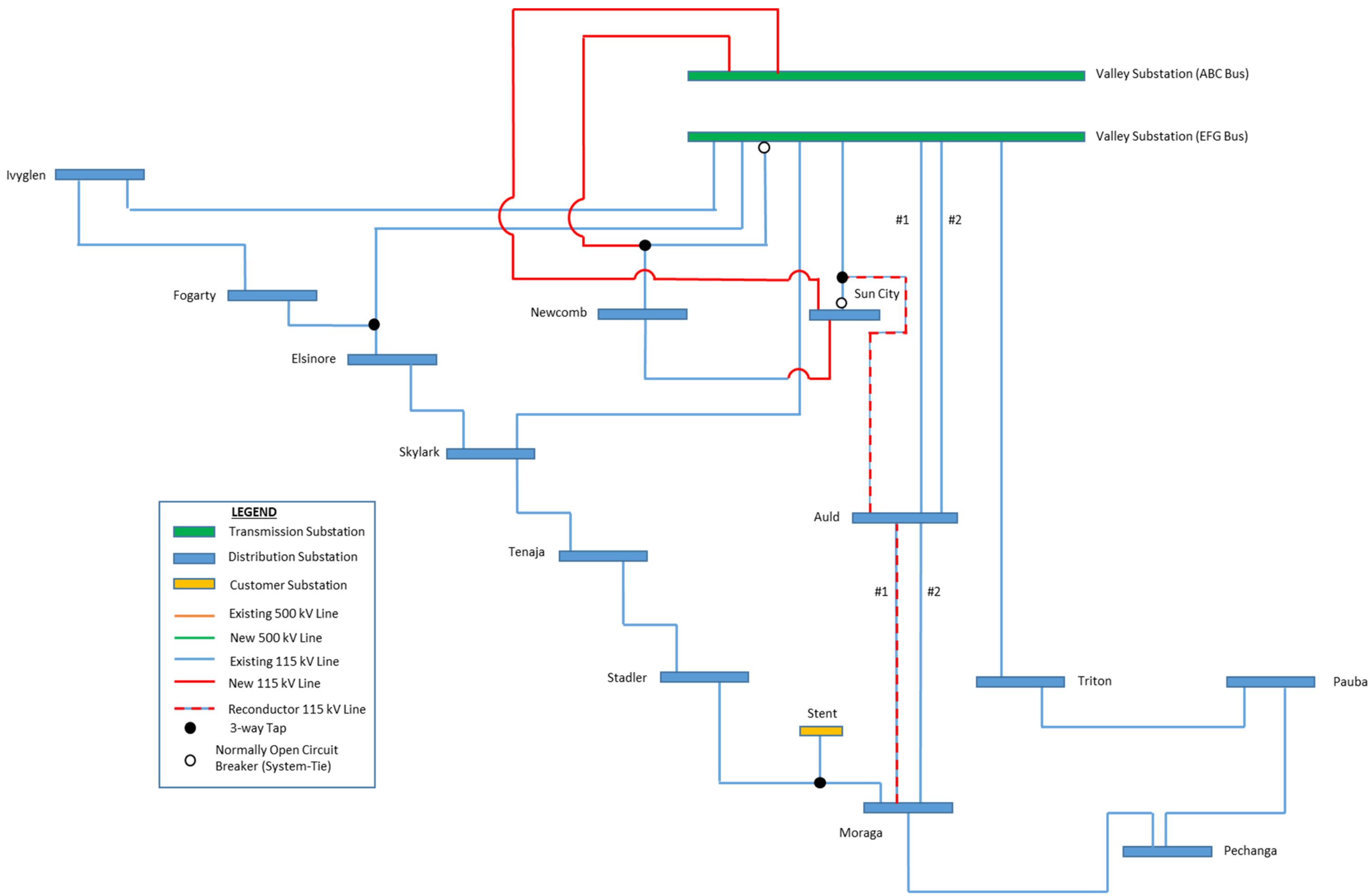
C.6 Valley South to Valley North

C.6.1 **System Solution Overview**

The Valley South to Valley North alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to SCE's existing Valley North 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed.

C.6.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-11 on the following page.



Schematic Representation. Not to scale.

Figure C-11. System One-Line Schematic of the Valley South to Valley North Alternative

C.6.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Sun City 115 kV subtransmission line (approximately 7.7 miles)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)

This system alternative would require the construction of approximately 5.9 miles of new 115 kV subtransmission line and the modification of approximately 14.9 miles of existing 115 kV subtransmission line. This system alternative totals approximately 20.8 miles. A detailed description of each of these components is provided in the subsections that follow.

<u>New 115 kV Single-Circuit Subtransmission Lines</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld-Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Reconductor Existing 115 kV Subtransmission Line

Auld-Sun City

SCE's existing Auld-Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the City of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 7.7 miles in length.

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena

Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

C.6.4 **Siting and Routing Map**

A siting and routing map of this alternative is provided in Figure C-12 on the following page.

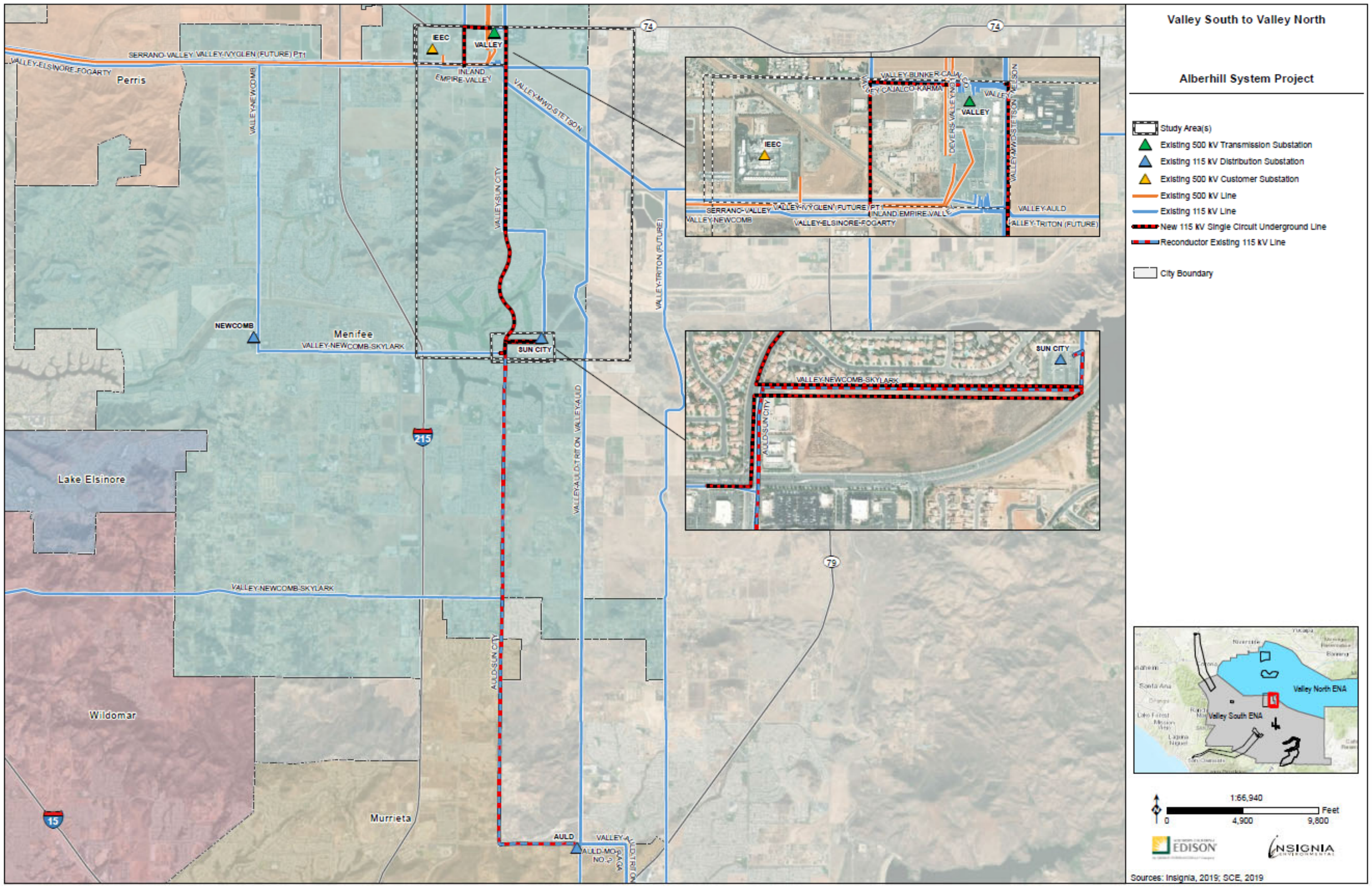


Figure C-12. Siting and Routing Map for the Valley South to Valley North Alternative[95]

[95] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.6.5 **Project Implementation Scope**

Table C-11 summarizes the scope for this alternative.

Table C-11. Valley South to Valley North Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Sun City	7.7 miles overhead reconductor existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position, repurpose position No. 2 for 115 kV line with (1) line protection upgrade, and (1) line protection upgrade
Valley	Equip 115 kV Position 7 with (2) new 115 kV Lines, and (2) line protection upgrades on Valley South switchrack.
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 18,900 feet
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Real Properties	
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Auld-Sun City	New Easement – (15) Parcels (2 miles, 30 ft. wide, 7.27 acres total)
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
N/A	N/A

C.6.6 **Cost Estimate Detail**

Table C-12 summarizes the costs for this alternative.

Table C-12. Valley South to Valley North Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	10
Substation Estimate	4
Owners Agent (10% of construction)	6
Corporate Security	n/a
Bulk Transmission	n/a
Subtransmission	100
Transmission Telecom	3
Distribution	2
IT Telecom	1
RP	6
Environmental	15
Subtotal Direct Cost	**169**
Subtotal Battery Cost	**n/a**
Uncertainty	52
Total with Uncertainty	**221**
Total Capex	**221**
PVRR	**207**

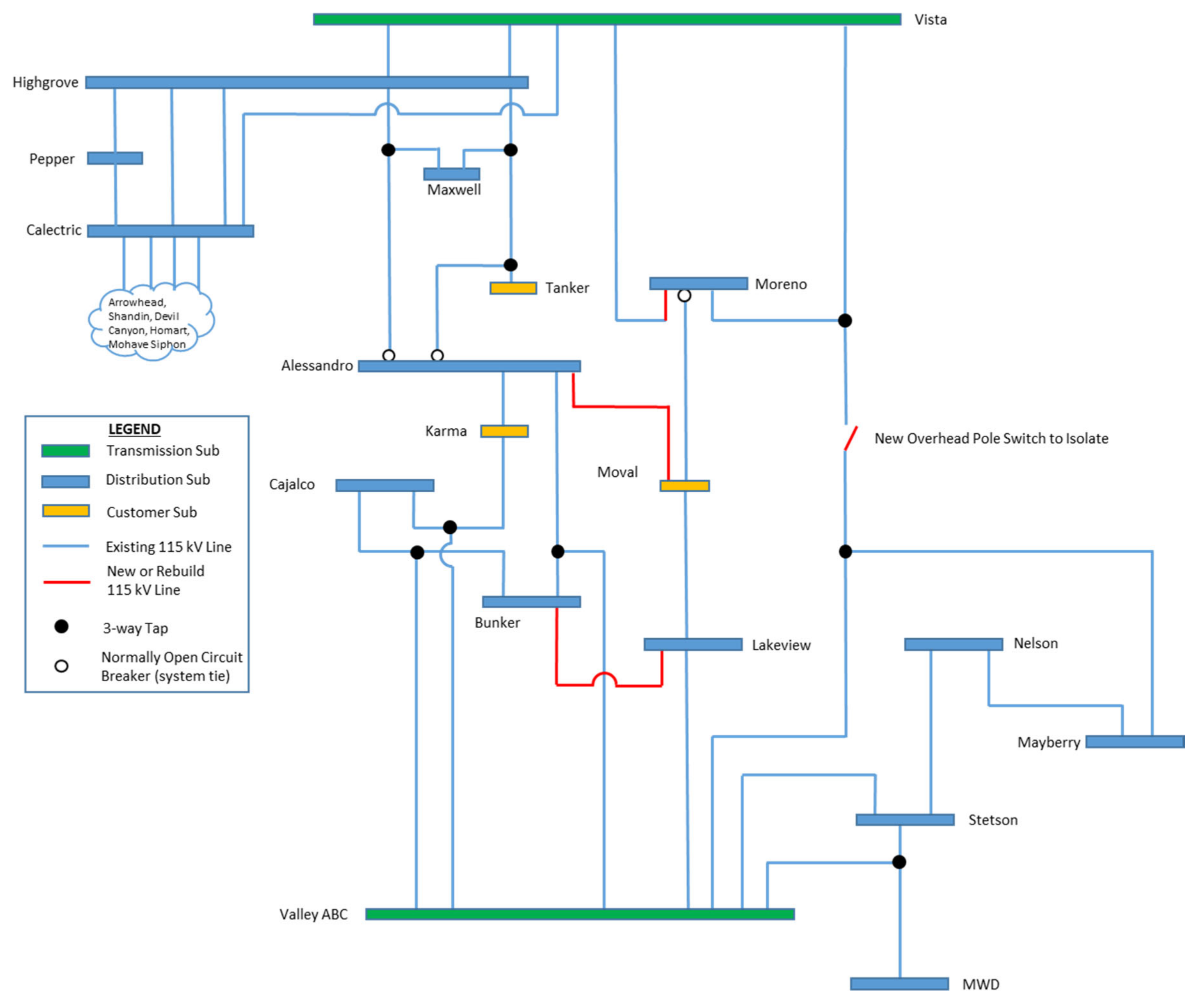
C.7 Valley South to Valley North to Vista

C.7.1 System Solution Overview

The Valley South to Valley North to Vista alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to the Valley North 500/115 kV System, and away from the Valley North 500/115 kV System to the Vista 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations from the Valley South to the Valley North System, and the Moreno 115/12 kV distribution substation to the Vista System. Subtransmission line construction and modifications in Valley South create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed. Subtransmission line construction and modifications in Valley North create two system-ties between the Valley North and Vista Systems. These system-tie lines would allow for the transfer of load from the Vista system back to the Valley North System (Moreno Substation) as well as additional load transfer from the Valley North System to the Vista System (Mayberry Substation) as needed.

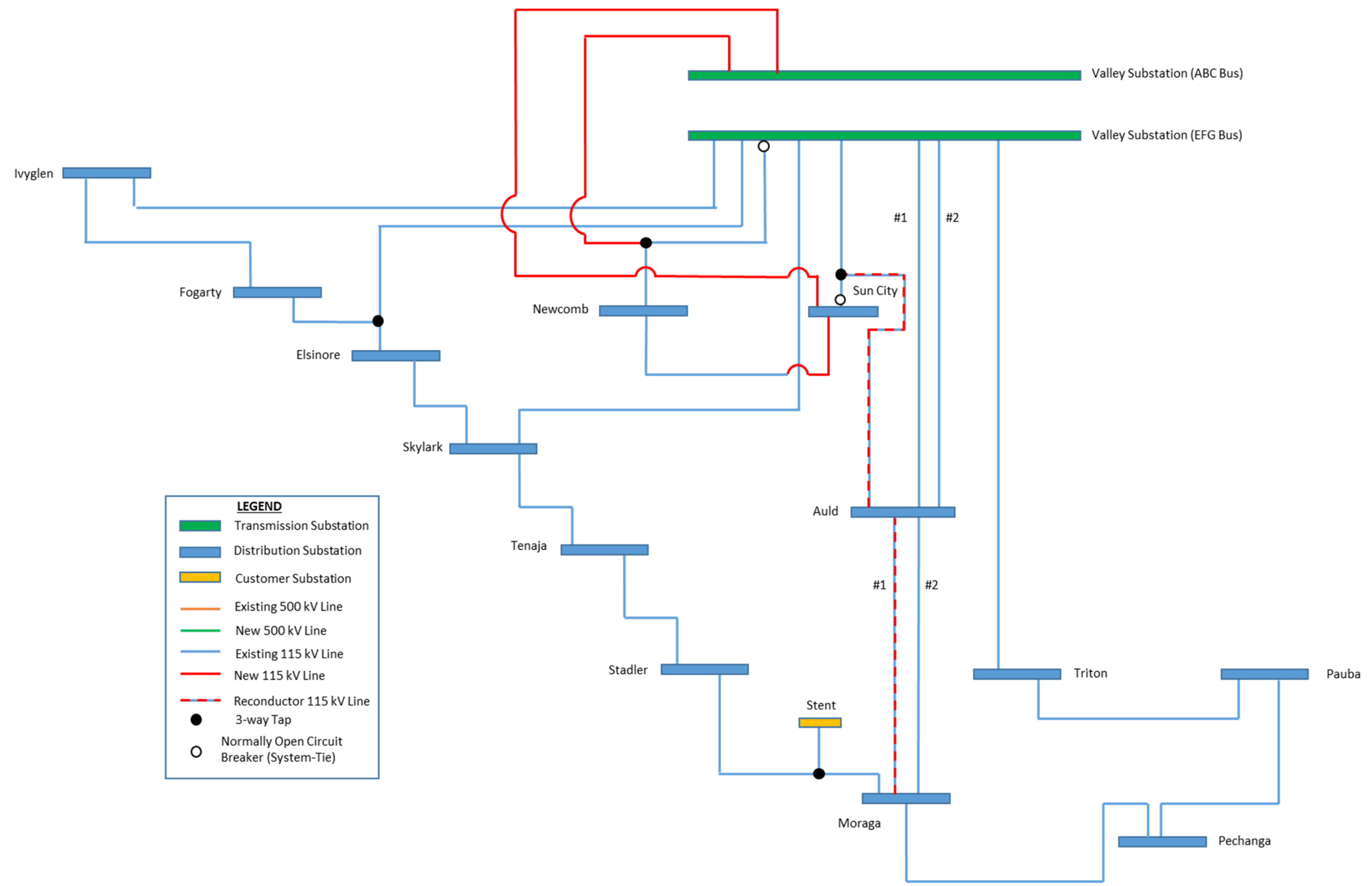
C.7.2 System One-Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-13 and Figure C-14 on the following pages (Valley North portion and Valley South portion, respectively).



Schematic Representation. Not to scale.

Figure C-13. System One-Line Schematic of the Valley South to Valley North to Vista Alternative (Valley North Portion)



Schematic Representation. Not to scale.

Figure C-14. System One-Line Schematic of the Valley South to Valley North to Vista Alternative (Valley South Portion)

C.7.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 115 kV Bunker and Lakeview Substations (approximately 6 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 115 kV Alessandro and Moval Substations (approximately 4 miles)
- Reconductor SCE's existing, single-circuit Auld-Sun City 115 kV subtransmission line (approximately 7.7 miles)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Double-circuit a segment of SCE's existing 115 kV Moreno-Moval-Vista subtransmission line (approximately 0.1 mile)

This system alternative would require the construction of approximately 15.9 miles of new 115 kV subtransmission line and the modification of approximately 15 miles of existing 115 kV subtransmission line. This system alternative totals approximately 31 miles. A detailed description of each of these components is provided in the subsections that follow.

<u>New 115 kV Single-Circuit Subtransmission Lines</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south for approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, which is approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east and parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north, under SCE's existing transmission corridor, and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west and parallel to SCE's existing Auld-Sun City 115 kV subtransmission line until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Bunker Substation to Lakeview Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Bunker Substation in the City of Perris and SCE's existing 115 kV Lakeview Substation in Riverside County. From SCE's existing 115 kV Bunker Substation, the line would extend south on Wilson Avenue on new structures for approximately 0.4 miles until the intersection with Placentia Avenue. At this intersection, the line would extend east on Placentia Avenue for approximately 0.4 mile, then turn south for approximately 0.3 miles and travel parallel to a dry creek bed until the intersection with Water Avenue. At the intersection with Water Avenue, the line would leave the City of Perris, extending east for approximately 0.8 miles until the intersection with Bradley Road. The line would then continue east across vacant and agricultural lands for approximately 2.1 miles until intersecting SCE's existing Valley-Lakeview 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Valley-Lakeview 115 kV subtransmission line for approximately 2 miles, extending north until terminating at SCE's existing 115 kV Lakeview Substation. The current route extends north, southeast along 11th Street, and northeast along an unpaved access road before arriving at SCE's existing 115 kV Lakeview Substation. This segment of the system alternative would be approximately 6 miles in length.

Alessandro Substation to Moval Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Alessandro and Moval Substations in the City of Moreno Valley. The new line would exit SCE's existing 115 kV Alessandro Substation in an underground configuration and extend north for approximately 350 feet along Kitching Street until intersecting John F Kennedy Drive. At this intersection, the line would transition to an overhead configuration on new structures and extend east along John F Kennedy Drive for approximately 0.5 miles until the intersection with Lasselle Street. The line would then extend north on Lasselle Street for approximately 1 mile until the intersection with Alessandro Boulevard, where the line would extend east for approximately 2 miles until intersecting Moreno Beach Drive and SCE's existing Lakeview-Moval 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Lakeview-Moval 115 kV subtransmission line for approximately 0.5 miles until terminating at SCE's existing 115 kV Moval Substation. The current route extends north along Moreno Beach Drive until reaching SCE's existing 115 kV Moval Substation, approximately 0.1 miles south of the intersection of Moreno Beach Drive and Cottonwood Avenue. This segment of the system alternative would be approximately 4 miles in length.

Reconductor Existing 115 kV Subtransmission Line

Auld-Sun City

SCE's existing Auld-Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the City of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 7.7 miles in length.

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for

approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

Double-Circuit Existing 115 kV Subtransmission Lines

SCE currently operates an existing, single-circuit Moreno-Moval-Vista 115 kV subtransmission line between SCE's existing 115 kV Moreno, Moval, and Vista Substations. An approximately 0.1-miles segment of this line within the City of Moreno Valley would be converted from a single-circuit to double-circuit configuration. This segment would begin at the intersection of Ironwood Avenue and Pettit Street and extend east before turning north and entering SCE's existing 115 kV Moreno Substation.

C.7.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-15 on the following page.

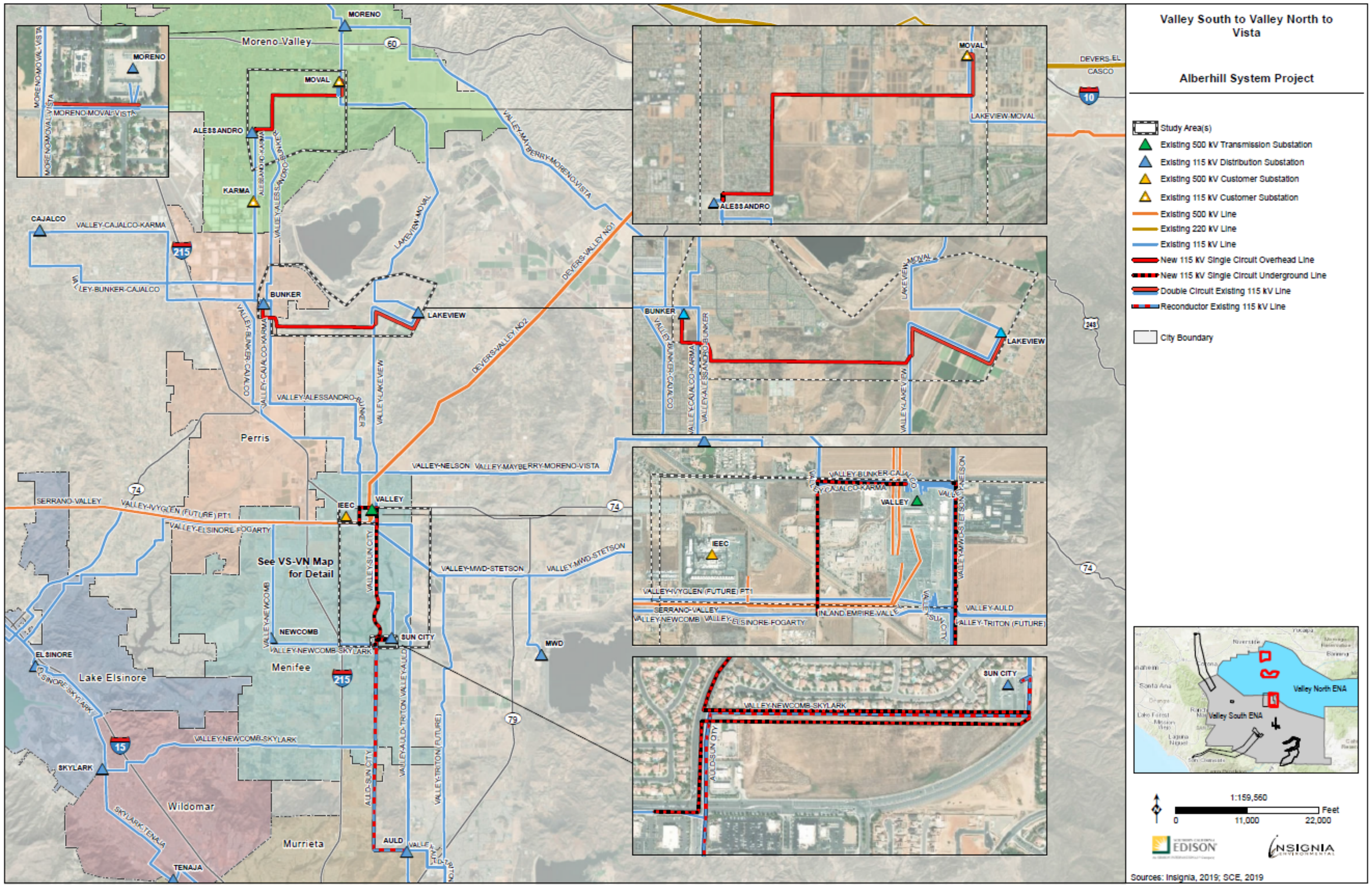


Figure C-15. Siting and Routing Map for the Valley South to Valley North to Vista Alternative[96]

[96] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.7.5 **Project Implementation Scope**

Table C-13 summarizes the scope for this alternative.

Table C-13. Valley South to Valley North to Vista Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Sun City	7.7 miles overhead reconductor existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Alessandro-Moval	4 miles (3.5 overhead single-circuit , 0.1 underground single-circuit , and 0.4 overhead double-circuit existing)
Bunker-Lakeview	6 miles (3.9 overhead single-circuit , 2.1 overhead double-circuit existing)
Moreno-Moval	0.1 miles overhead double-circuit existing
Vista-Valley-Mayberry	Install (1) 115 kV pole switch
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position , repurpose Position No. 2 for 115 kV line with (1) line protection upgrade, and (1) line protection upgrade
Valley North (ABC)	Equip 115 kV Position 7 with (2) new 115 kV lines, and (2) line protection upgrades on Valley North (ABC) switchrack
Moreno	(1) 115 kV line position
Moval	(2) 115 kV line position and (1) line protection upgrade
Bunker	Equip (1) 115 kV line position
Lakeview	Equip (1) 115 kV line position
Alessandro	Build and equip (1) 115 kV line position
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 19,200 feet
Replace Existing Single-Circuit Overhead	Approximately 12,800 feet
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Alessandro-Moval	4 miles (3.9 overhead, 0.1 underground) fiber optic cable
Bunker-Lakeview	6. miles overhead fiber optic cable

Scope	Detailed Scope Element
Moreno-Moval	0.1 miles overhead fiber optic cable
Real Properties	
Alessandro-Moval	New Easement – (20) Parcels (1 mile, 30 ft. wide, 9.09 acres total)
Bunker-Lakeview	New Easement – (45) Parcels (5 miles, 30 ft. wide, 18.18 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Auld-Sun City	New Easement – (15) Parcels (2 miles, 30 ft. wide, 7.27 acres total)
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
N/A	N/A

C.7.6 **Cost Estimate Detail**

Table C-14 summarizes the costs for this alternative.

Table C-14. Valley South to Valley North to Vista Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	17
Substation Estimate	8
Owners Agent (10% of construction)	9
Corporate Security	n/a
Bulk Transmission	n/a
Subtransmission	132
Transmission Telecom	4
Distribution	3
IT Telecom	2
RP	19
Environmental	28
Subtotal Direct Cost	**238**
Subtotal Battery Cost	**n/a**
Uncertainty	79
Total with Uncertainty	**317**
Total Capex	**317**
PVRR	**290**

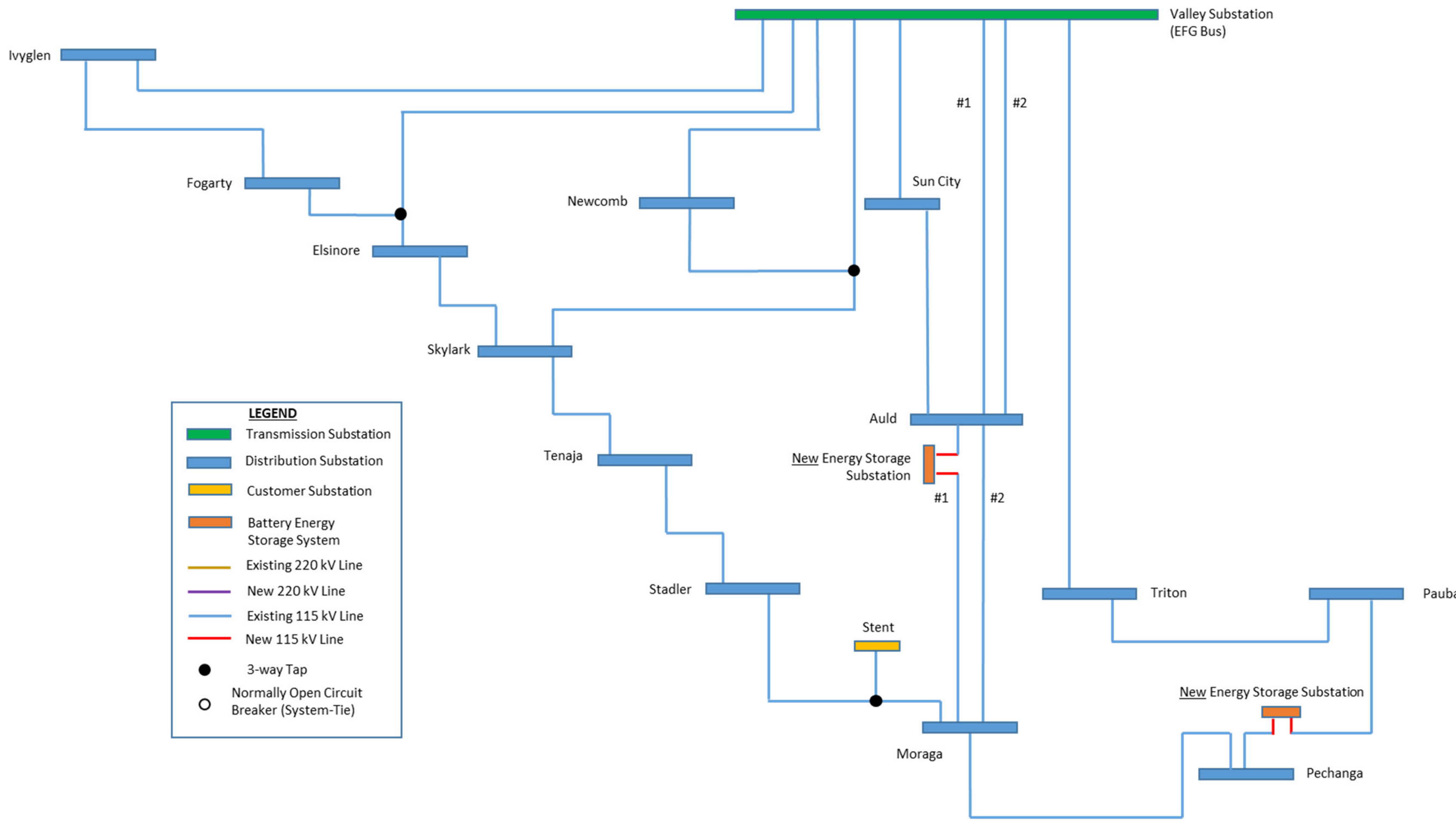
C.8 Centralized BESS in Valley South

C.8.1 **System Solution Overview**

The Centralized Battery Energy Storage System (BESS) in Valley South alternative proposes to reduce peak demand in the Valley South 500/115 kV System via construction of two new 115/12 kV substations with BESSs near Pechanga and Auld Substations, which would loop-in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.

C.8.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-16 on the following page.



Schematic Representation. Not to scale.

Figure C-16. System One-Line Schematic for the Centralized BESS in Valley South Alternative

C.8.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct two new 115/12 kV substations with BESSs (approximately 9-acre footprint each)
- Construct two new 115 kV subtransmission segments to loop the new BESSs into the Valley South 115 kV System.

A detailed description of each of these components is provided in the subsections that follow.

<u>BESS and 115 kV Loop-ins</u>

Pechanga BESS and Loop-in

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the City of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line, which is directly adjacent to the site, would be looped into the 115 kV Pechanga BESS.

Auld BESS and Loop-in

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 26.4-acre, privately owned parcel in the City of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld-Moraga 115 kV subtransmission line, which is directly adjacent to the site, would be looped into the 115 kV Auld BESS.

C.8.4 **Siting and Routing Map**

A siting and routing map of this alternative is provided in Figure C-17 on the following page.

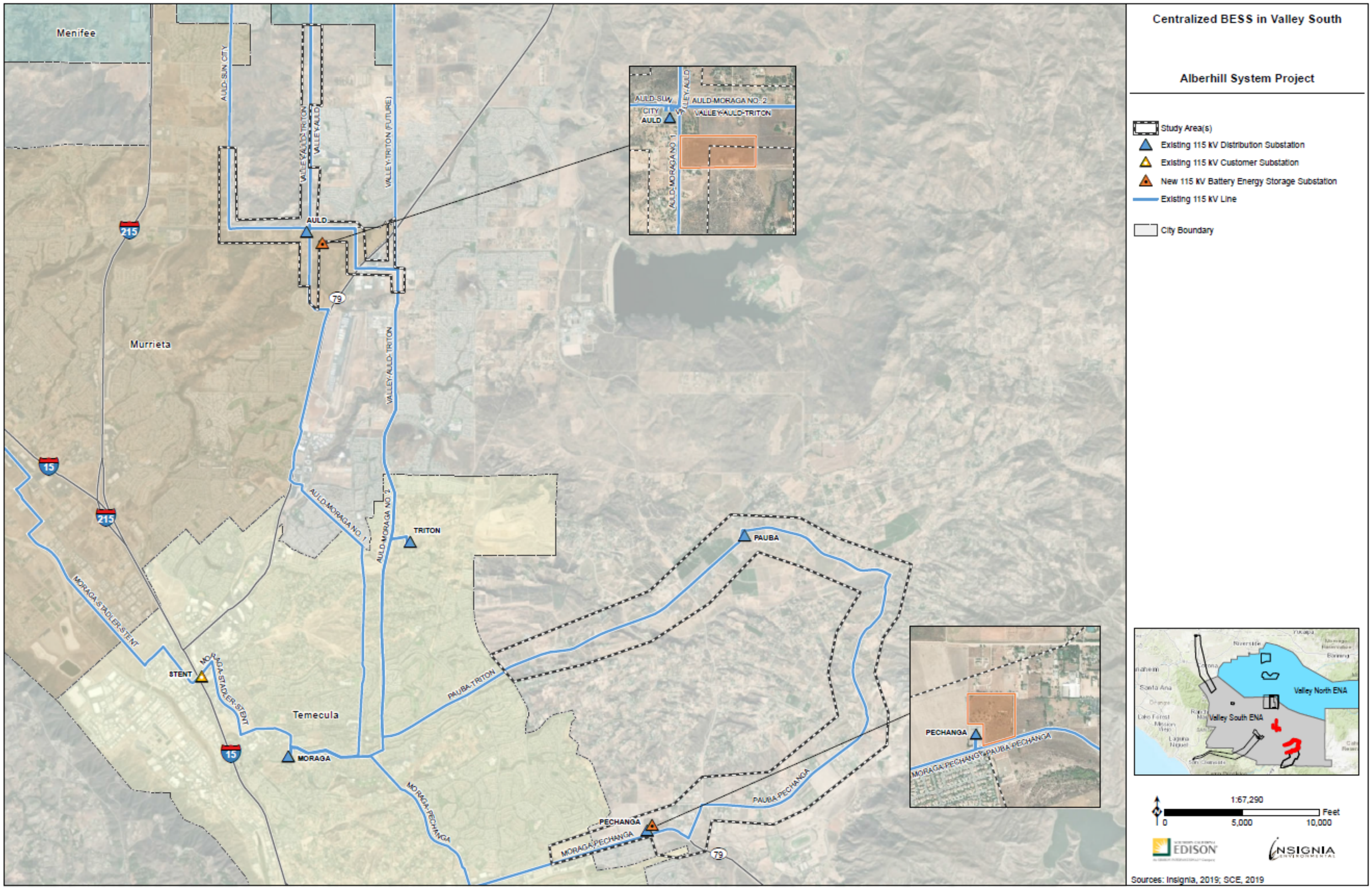


Figure C-17. Siting and Routing for the Centralized BESS in Valley South Alternative

C.8.5 Project Implementation Scope

Table C-15 summarizes the scope of this alternative.

Table C-15. Centralized BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 115/12 kV Substation with BESS (adjacent to Auld Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 115/12 kV Substation with BESS (adjacent to Pechanga Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV line protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
Support Scope Elements	
Real Properties	
Pechanga BESS Location B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
Auld BESS Location C-A-04	Fee Acquisition – (1) 24.56-Acre Parcel
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New BESS Locations	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-16 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-16. Battery Installations

Year	PVWatts Forecast		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
2022	68	216	2022	71	216	2021	110	433
2027	5	31	2027	47	281	2026	64	436
2032	46	237	2032	57	377	2031	64	506
2027	45	286	2027	52	417	2036	61	485
2042	38	299	2042	46	375	2041	54	491
						2046	18	191
Total	202	1069	Total	273	1666	Total	371	2542

C.8.6 Cost Estimate Detail

Table C-17 summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-17. Centralized BESS in Valley South Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	55	91	102
Substation Estimate	52	86	96
Owners Agent (10% of construction)	3	5	6
Corporate Security	3	3	3
Bulk Transmission	n/a	n/a	n/a
Subtransmission	3	3	3
Transmission Telecom	n/a	n/a	n/a
Distribution	n/a	n/a	n/a
IT Telecom	1	1	1
RP	5	5	5
Environmental	13	13	13
Subtotal Direct Cost	**111**	**147**	**158**
Subtotal Battery Cost	**681**	**1,013**	**1,729**
Uncertainty	213	314	476
Total with Uncertainty	**1,004**	**1,474**	**2,363**
Total Capex	**1,004**	**1,474**	**2,363**
Battery Revenue	**75**	**110**	**173**
PVRR	**381**	**525**	**848**

C.9 Valley South to Valley North and Distributed BESS in Valley South

C.9.1 System Solution Overview

The Valley South to Valley North and Distributed Battery Energy Storage System (BESS) alternative proposes to reduce peak demand in the Valley South 500/115 kV System via distributed BESSs at existing 115/12 kV distribution substations. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed.

C.9.2 System One-Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-18 on the following page.

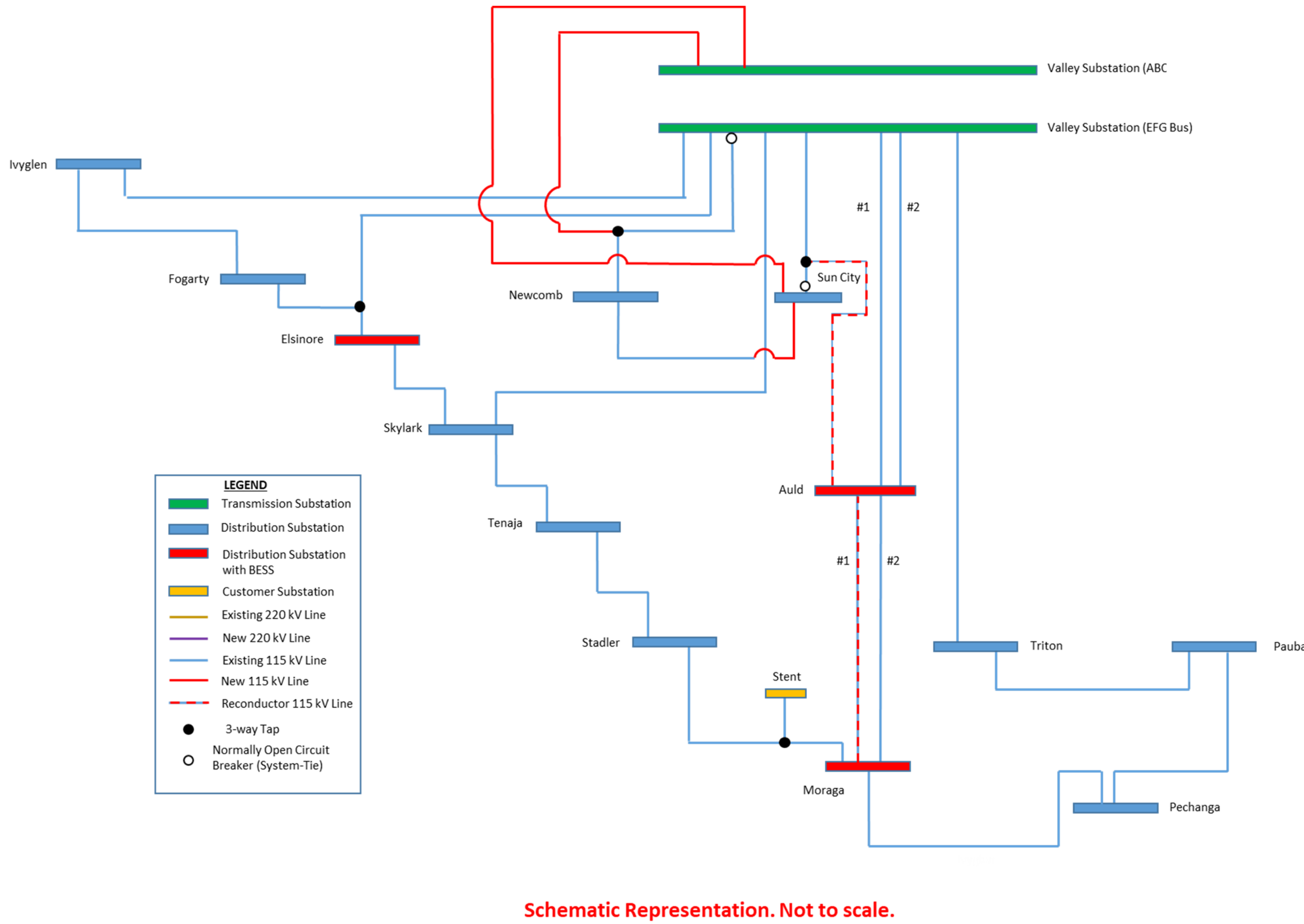


Figure C-18. System One-Line Schematic of the Valley South to Valley North and Distributed BESS in Valley South Alternative

C.9.3 Siting and Routing Description

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Sun City 115 kV subtransmission line (approximately 7.7 miles)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Construct new energy storage components within the existing fence lines at three existing SCE 115 kV substations

This system alternative would require the construction of approximately 5.9 miles of new 115 kV subtransmission line and the modification of approximately 14.9 miles of existing 115 kV subtransmission line. This system alternative totals approximately 20.8 miles. A detailed description of each of these components is provided in the subsections that follow.

New 115 kV Single-Circuit Subtransmission Lines

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld-Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Reconductor Existing 115 kV Subtransmission Line

Auld-Sun City

SCE's existing Auld-Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 miles until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the City of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 7.7 miles in length.

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for

approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

Energy Storage Components

This system alternative would require the installation of energy storage components within the existing fence line at three existing SCE 115 kV substations. A description of each of these substation locations is provided in the subsections that follow.

Auld Substation

SCE's existing 115 kV Auld Substation is located on approximately 4.1 acres of SCE-owned land southwest of the intersection of Los Alamos Road and Liberty Road in the City of Murrieta. This site is bounded by residential development to the south and west, and vacant land to the north and the east.

Elsinore Substation

SCE's existing 115 kV Elsinore Substation is located on approximately 2.1 acres of SCE-owned land south of the intersection of West Flint Street and North Spring Street in the City of Lake Elsinore. This site is bounded by vacant land to the west, commercial and residential uses to the north, residential uses to the east, and commercial uses to the south.

Moraga Substation

SCE's existing 115 kV Moraga Substation is located on approximately 4 acres of SCE-owned land and approximately 0.1 miles southwest of the intersection of Mira Loma Drive and Calle Violetta in the City of Temecula. This site is bounded on all sides by residential uses.

C.9.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-19 on the following page.

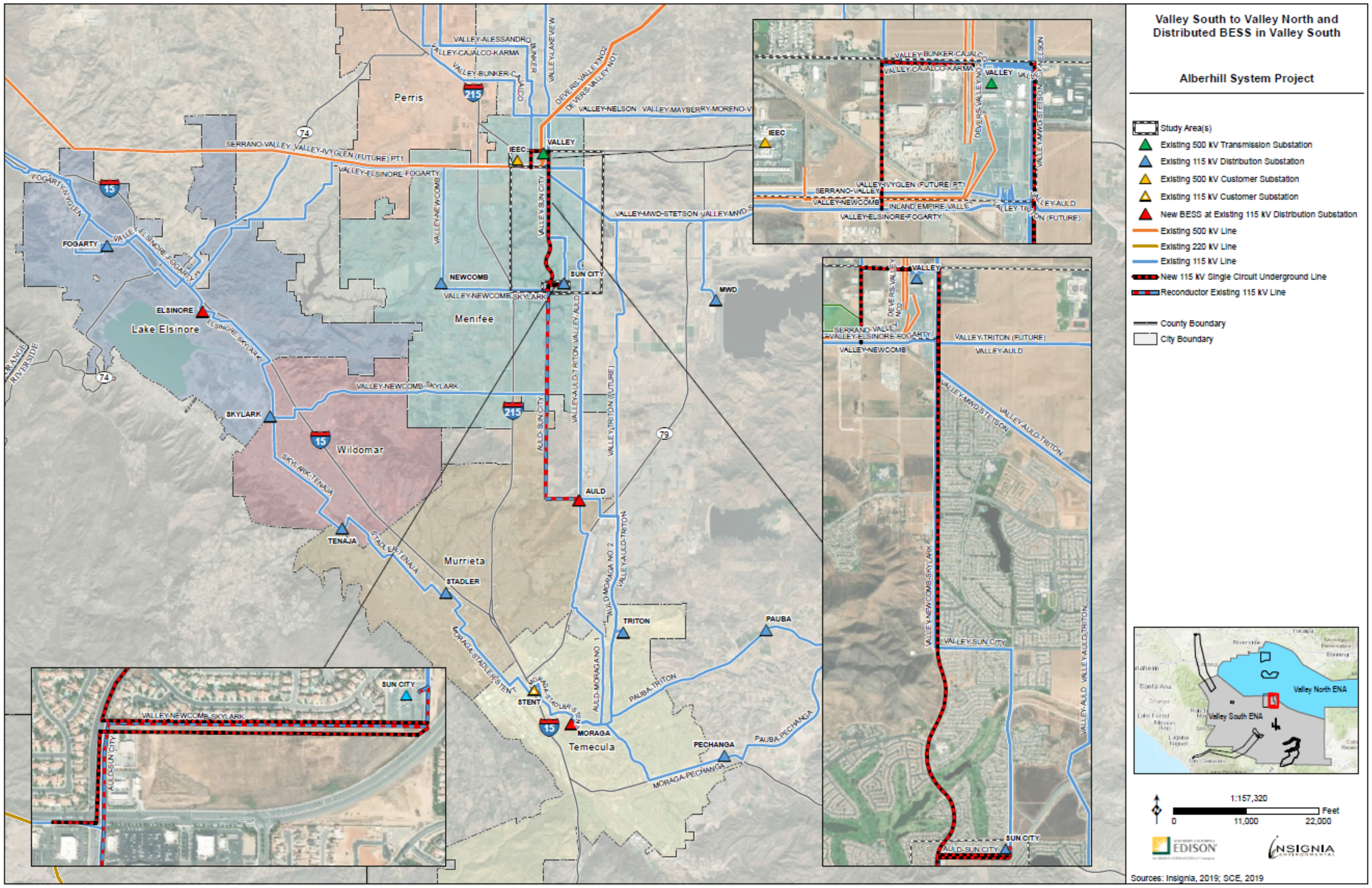


Figure C-19. Siting and Routing Map for the Valley South to Valley North and Distributed BESS in Valley South Alternative[97]

[97] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.9.5 **Project Implementation Scope**

Table C-18 summarizes the scope for this alternative.

Table C-18. Valley South to Valley North and Distributed BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
Auld Substation**	
Electrical	Equip (1) spare 12 kV position.
Batteries	10 MW/ 12 MWh
Elsinore Substation**	
Electrical	Equip (2) spare 33 kV positions.
Batteries	20 MW/ 38 MWh
Moraga**	
Electrical	Equip (2) spare 12 kV positions.
Batteries	20 MW/ 35 MWh
115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Sun City	7.7 miles overhead reconductor existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position, repurpose position No. 2 for 115 kV line with (1) line protection upgrade, and (1) line protection upgrade
Valley	Equip 115 kV Position 7 with (2) new 115 kV Lines, and (2) line protection upgrades on Valley South switchrack.
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 18,900 feet
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Real Properties	
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Auld-Sun City	New Easement – (15) Parcels

	(2 miles, 30 ft. wide, 7.27 acres total)
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
N/A	N/A

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-19 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-19. Battery Installations

Year	PVWatts Forecast1		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
-	-	-	2043	50	110	2036	50	122
Total	-	-	Total	50	110	Total	50	122

Note:

1. The PVWatts forecast does not necessitate a need for batteries to meet N-0 capacity requirements, i.e., the conventional scope of this alternative alone mitigates all N-0 transformer capacity overloads through the 30 -year horizon of the cost benefit analysis.

C.9.6 Cost Estimate Detail

Table C-20 summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-20. Valley South to Valley North and Distributed Battery Energy Storage System Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast[1]	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	10	13	13
Substation Estimate	4	7	7
Owners Agent (10% of construction)	6	6	6
Corporate Security	n/a	n/a	n/a
Bulk Transmission	n/a	n/a	n/a
Subtransmission	100	100	79
Transmission Telecom	3	3	3
Distribution	2	2	2
IT Telecom	1	1	1
RP	6	6	6
Environmental	15	15	15
Subtotal Direct Cost	**169**	**173**	**173**
Subtotal Battery Cost	**n/a**	**82**	**104**
Uncertainty	48	71	78
Total with Uncertainty	**218**	**326**	**354**
Total Capex	**218**	**326**	**354**
Battery Revenue	**n/a**	**2.2**	**6.4**
PVRR	**200**	**232**	**228**

Note:

1. The PVWatts forecast does not necessitate a need for batteries. The scope for this alternative under the PVWatts forecast is identical to the VS-VN alternative.

C.10 SDG&E and Centralized BESS in Valley South

C.10.1 System Solution Overview

The San Diego Gas and Electric (SDG&E) alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 230/115 kV system created at the southern boundary of the SCE service territory and adjacent to SDG&E's service territory. The new system would be provided power from the existing SDG&E 230 kV system via construction of a new 230/115 kV substation and looping in the SDG&E Escondido-Talega 230 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Pauba and Pechanga 115/12 kV distribution substations to the newly formed 230/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two 115 kV system-ties between the Valley South System and the newly formed 230/115 kV SDG&E-sourced system. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Pauba and Pechanga Substations) as well as additional load transfer from the Valley South System to the new system (Triton Substation) as needed.

To further reduce load in the Valley South System, a new 115/12 kV substation with BESS would be constructed near Auld Substation with a loop-in of the Auld-Moraga #1 line.

C.10.2 System Single Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-20 on the following page.

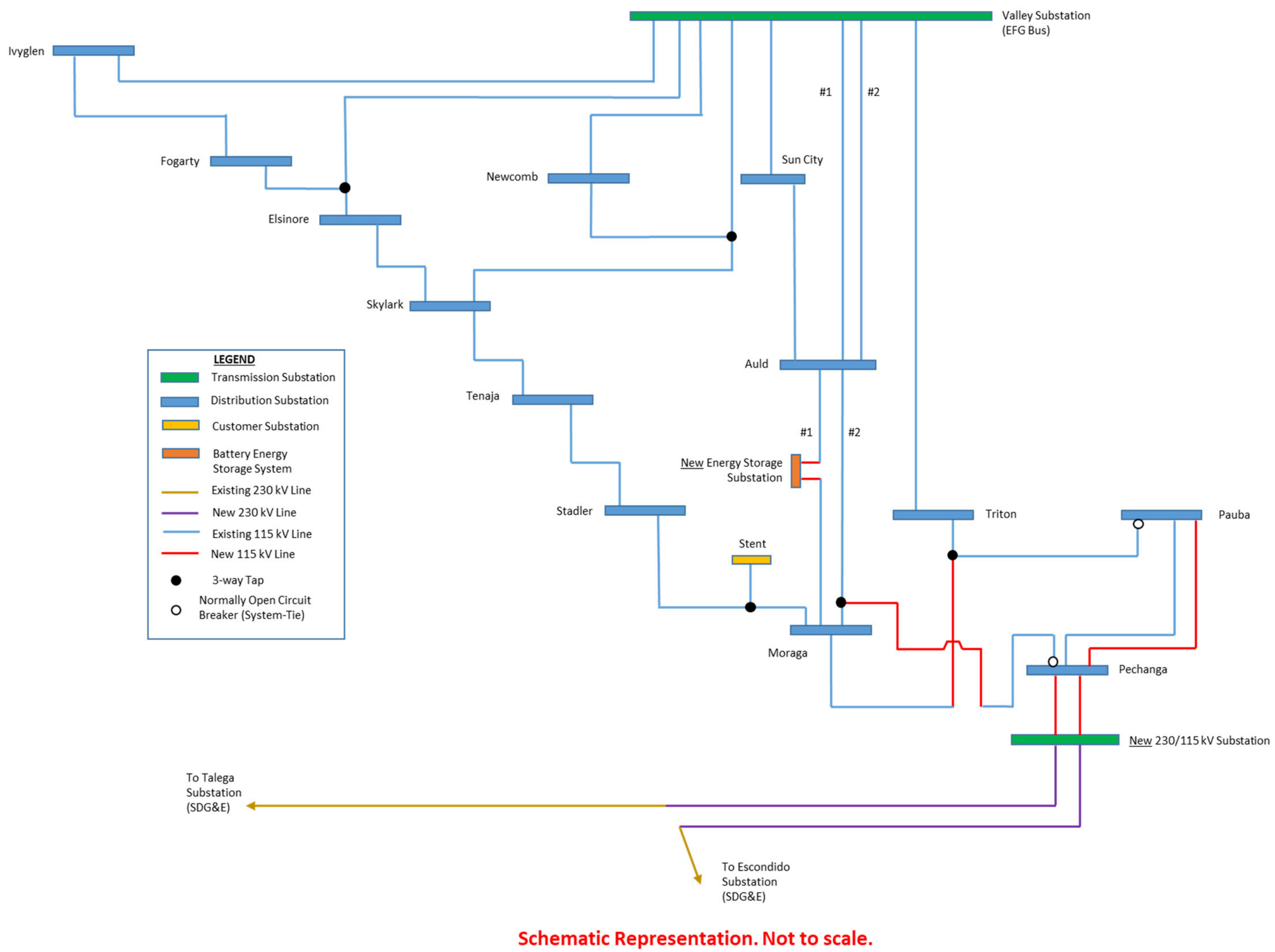


Figure C-20 System One-Line Schematic of the SDG&E and Centralized BESS in Valley South Alternative

C.10.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 230/115 kV substation (approximately 15-acre footprint)
- Construct a new 230 kV double-circuit transmission line between SDG&E's existing Escondido-Talega 230 kV transmission line and Southern California Edison's (SCE's) new 230/115 kV substation (approximately 7.2 miles)
- Construct a new 115 kV double-circuit subtransmission line between SCE's new 230/115 kV substation and SCE's existing Pechanga Substation (approximately 2 miles)
- Demolish SCE's existing 115 kV switchrack at Pechanga Substation and reconstruct it on an adjacent parcel (approximately 3.2-acre footprint)
- Double-circuit SCE's existing Pauba-Pechanga 115 kV subtransmission line (approximately 7.5 miles)
- Double-circuit a segment of SCE's existing Auld-Moraga #2 115 kV subtransmission line (approximately 0.3 mile)
- Construct one new 115/12 kV substation with BESS (approximately 9-acre footprint)
- Construct one new 115 kV subtransmission segment to loop the new 115 kV BESS into SCE's existing 115 kV subtransmission system

This system alternative would require the construction of approximately 9.2 miles of new 230 kV transmission and 115 kV subtransmission lines and the modification of approximately 7.8 miles of existing 115 kV subtransmission line. This system alternative totals approximately 17 miles. A detailed description of each of these components is provided in the subsections that follow.

New 230/115 kV Substation

SDG&E would include the construction of a new, approximately 15-acre, 230/115 kV substation on a privately owned, approximately 56.4-acre, vacant parcel. The parcel is located north of Highway 79, between the intersections with Los Caballos Road and Pauba Road, in Riverside County. The parcel is trapezoidal in shape and is bounded by residences and equestrian facilities to the north, east, and west; and Highway 79 and vacant land to the south. SCE may establish vehicular access to the site from Los Corralitos Road or Highway 79.

New 230 kV Double-Circuit Transmission Line

A new 230 kV double-circuit transmission line would be constructed, connecting the new 230/115 kV substation to SDG&E's existing Escondido-Talega 230 kV transmission line. This new 230 kV transmission line would begin at SDG&E's existing 230 kV Escondido-Talega 230 kV transmission line approximately 0.6 miles northeast of the intersection of Rainbow Heights Road and Anderson Road in the community of Rainbow in San Diego County. The line would leave the interconnection with SDG&E's existing Escondido-Talega 230 kV transmission line on new structures extending to the northeast for approximately 0.8 mile. At this point, the new line would enter Riverside County and the Pechanga Reservation for approximately 4 miles. The line would continue in a generally northeast direction for approximately 1 miles before exiting the Pechanga Reservation and continue until intersecting Highway 79. At the intersection with Highway 79, the line would extend northwest and parallel to Highway 79 for approximately 1 miles until reaching the new 230/115 kV substation. This segment of the system alternative would be approximately 7.2 miles in length.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line would be constructed to connect the new 230/115 kV substation to SCE's existing 115 kV Pechanga Substation. The line would depart the new 230/115 kV substation to the northwest on new structures for approximately 1.5 miles while traveling parallel to Highway 79. Near the intersection of Highway 79 and Anza Road, the line would transition to an underground configuration and continue along Highway 79 for approximately 0.5 miles until reaching SCE's existing 115 kV Pechanga Substation. This segment of the system alternative would be approximately 2 miles in length.

Demolish and Reconstruct an Existing 115 kV Switchrack

SCE currently operates the existing 115 kV Pechanga Substation, located on an approximately 3.2-acre, SCE-owned parcel approximately 0.2 miles northeast of the intersection of Highway 79 and Horizon View Street. This site is bounded by vacant land to the east and west and residential uses to the north and south. SCE would demolish this existing 115 kV switchrack and reconstruct it on an approximately 16.9-acre, privately owned parcel directly east of the existing substation. The new 115 kV switchrack would occupy approximately 3.2 acres within the parcel.

Double-Circuit Existing 115 kV Subtransmission Lines

Pauba-Pechanga

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Pauba and Pechanga Substations in Riverside County. This existing line would be converted to a double-circuit configuration, adding a new 115 kV circuit between SCE's existing 115 kV Pauba and Pechanga Substations. The existing line departs SCE's existing 115 kV Pechanga Substation and extends east along Highway 79 until reaching Anza Road. At the intersection of Highway 79 and Anza Road, the line extends northeast along Anza Road until reaching De Portola Road. At this intersection, the line extends generally northeast along De Portola Road until intersecting Monte de Oro Road, then the line extends west along Monte de Oro Road until reaching Rancho California Road. At this point, the line extends south along Rancho California Road and terminates at SCE's existing 115 kV Pauba Substation. This segment of the system alternative is approximately 7.5 miles in length.

Auld-Moraga #2

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Auld Substation in the City of Murrieta and SCE's existing 115 kV Moraga Substation in the City of Temecula. An approximately 0.3-miles segment of this line within the City of Temecula would be converted from a single-circuit to double-circuit configuration. This segment would begin near the intersection of Rancho California Road and Calle Aragon. The existing line then extends south before turning west and intersecting Margarita Road, approximately 0.2 miles northwest of Rancho Vista Road.

BESS and 115kV Loop-In

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 24.6-acre, privately owned parcel in the City of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld-Moraga 115 kV subtransmission line, which is directly adjacent to the site, would be looped into the 115 kV Auld BESS.

C.10.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-21 on the following page.

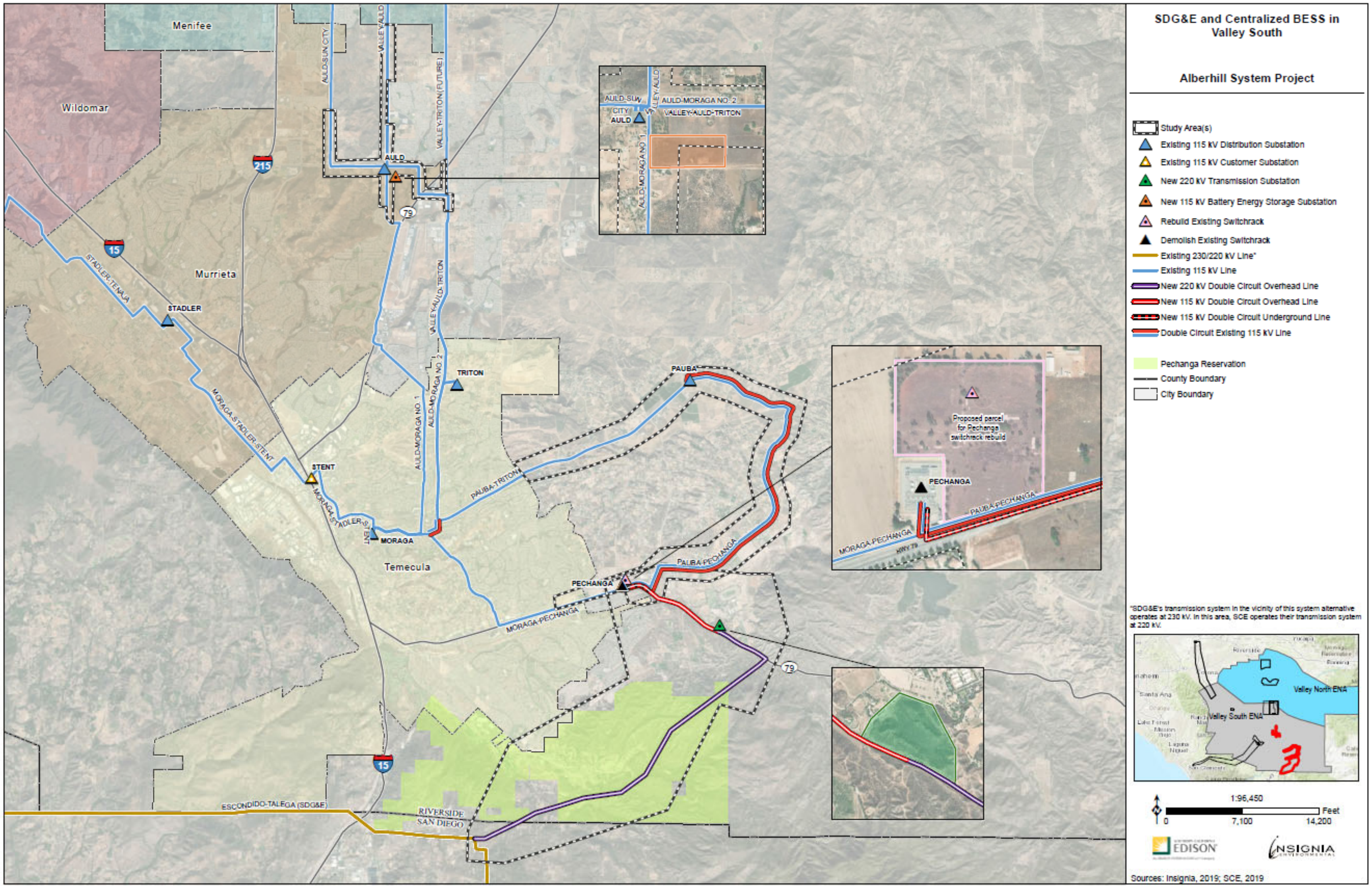


Figure C-21. Siting and Routing Map for the SDG&E and Centralized BESS in Valley South Alternative

C.10.5 **Project Implementation Scope**

Table C-21 summarizes the scope for this alternative.

Table C-21. SDG&E and Centralized BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 230/115 kV Station	
Electrical	New (3) position, (4) element 230 kV breaker-and-a-half switchrack to accommodate (2) banks & (2) lines
	(2) 280 MVA, 230/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	230 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 115/12 kV Station (adjacent to Auld Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 230 kV Transmission Line	
Loop-in SDG&E Escondido-Talega 230 kV line into New 230/115 kV Substation	7.3 miles overhead double-circuit 230 kV line
New 115 kV Subtransmission Lines	
New 230/115 kV Substation to Pechanga Substation	2 miles (1.4 overhead double-circuit, 0.6 underground double-circuit)
Pauba-Pechanga	7.5 miles overhead double-circuit existing
Moraga-Pauba-Triton	0.3 miles overhead double-circuit existing

Scope	Detailed Scope Element
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Escondido	(1) 230 kV line protection upgrade
Moraga	(1) 115 kV line protection upgrade
Pechanga	
Civil	Demo the existing 115 kV switchrack
	Extend existing perimeter fence with a guardian 5000 fence
Electrical	New (6) position, (8) element 115 kV BAAH switchrack to accommodate (3) banks & (5) lines.
	New 115 kV line protection. Replace bank protection.
	HMI upgrade.
Talega	(1) 230 kV line protection upgrade
Triton	(1) 115 kV line protection upgrade
Pauba	Equip (1) 115 kV line position and (1) 115 kV line protection upgrade
Distribution	
Station Light & Power – New Single Circuit Underground	Approximately 3,300 feet
Replace Existing Single Circuit Underbuild	Approximately 24,200 feet
Replace Existing Double Circuit Underbuild	Approximately 17,200 feet
Transmission Telecom	
SDG&E Escondido-Talega 230kV line to New 230/115 Substation	7.3 miles overhead fiber optic cable
New 230/115 kV Substation to Pechanga Substation	2 miles (1.4 miles overhead, 0.6 miles underground) fiber optic cable
Pauba-Pechanga	7.5 miles overhead fiber optic cable
Moraga-Pauba-Triton	0.3 miles overhead fiber optic cable
Real Properties	
SDG&E Substation A-A-04	Fee Acquisition – (1) 11.01-Acre Parcel
Pechanga Substation B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
SDG&E 230 kV Transmission Line	New Easement – (10) Parcels (2.5 miles, 100 ft. wide, 30.3 acres total)
SDG&E 115 kV Subtransmission Line	New Easement – (6) Parcels (2 miles, 30 ft. wide, 7.3 acres total)
Pauba-Pechanga 115 kV Subtransmission Line	New Easement – (9) Parcels (1.5 miles, 30 ft. wide, 5.5 acres total)
Auld-Moraga #2 115 kV Subtransmission Line	New Easement – (4) Parcels (0.33 miles, 30 ft. wide, 1.2 acres total)
Auld BESS Location C-A-04	Fee Acquisition – (1) 24.56-Acre Parcel
SDG&E Laydown Yards	Lease – (2) 15-Acre Parcels for 96 months
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.

Scope	Detailed Scope Element
Corporate Security	
New 230/115 kV Substation; Auld BESS Location	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-22 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-22. Battery Installations

Year	PVWatts Forecast		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
2048	20	64	2039	65	189	2033	82	262
-	-	-	2044	25	130	2038	56	323
-	-	-	-	-	-	2043	49	323
Total	20	64	Total	90	319	Total	187	908

C.10.6 **Cost Estimate Detail**

Table C-23 summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-23. SDG&E and Centralized BESS in Valley South Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast	**Effective PV Forecast**	**Spatial Base Forecast**
Licensing	31	31	31
Substation	132	142	159
Substation Estimate	114	123	140
Owners Agent (10% of construction)	18	19	20
Corporate Security	4	4	4
Bulk Transmission	112	112	112
Subtransmission	43	43	43
Transmission Telecom	3	3	3
Distribution	6	6	6
IT Telecom	4	4	4
RP	23	23	23
Environmental	43	43	43
Subtotal Direct Cost	**402**	**411**	**429**
Subtotal Battery Cost	**47**	**195**	**542**
Uncertainty	237	317	503
Total with Uncertainty	**685**	**923**	**1,473**
Total Capex	**685**	**923**	**1,473**
Battery Revenue	**n/a**	**7.6**	**33**
PVRR	**479**	**531**	**658**

C.11 Mira Loma and Centralized BESS in Valley South

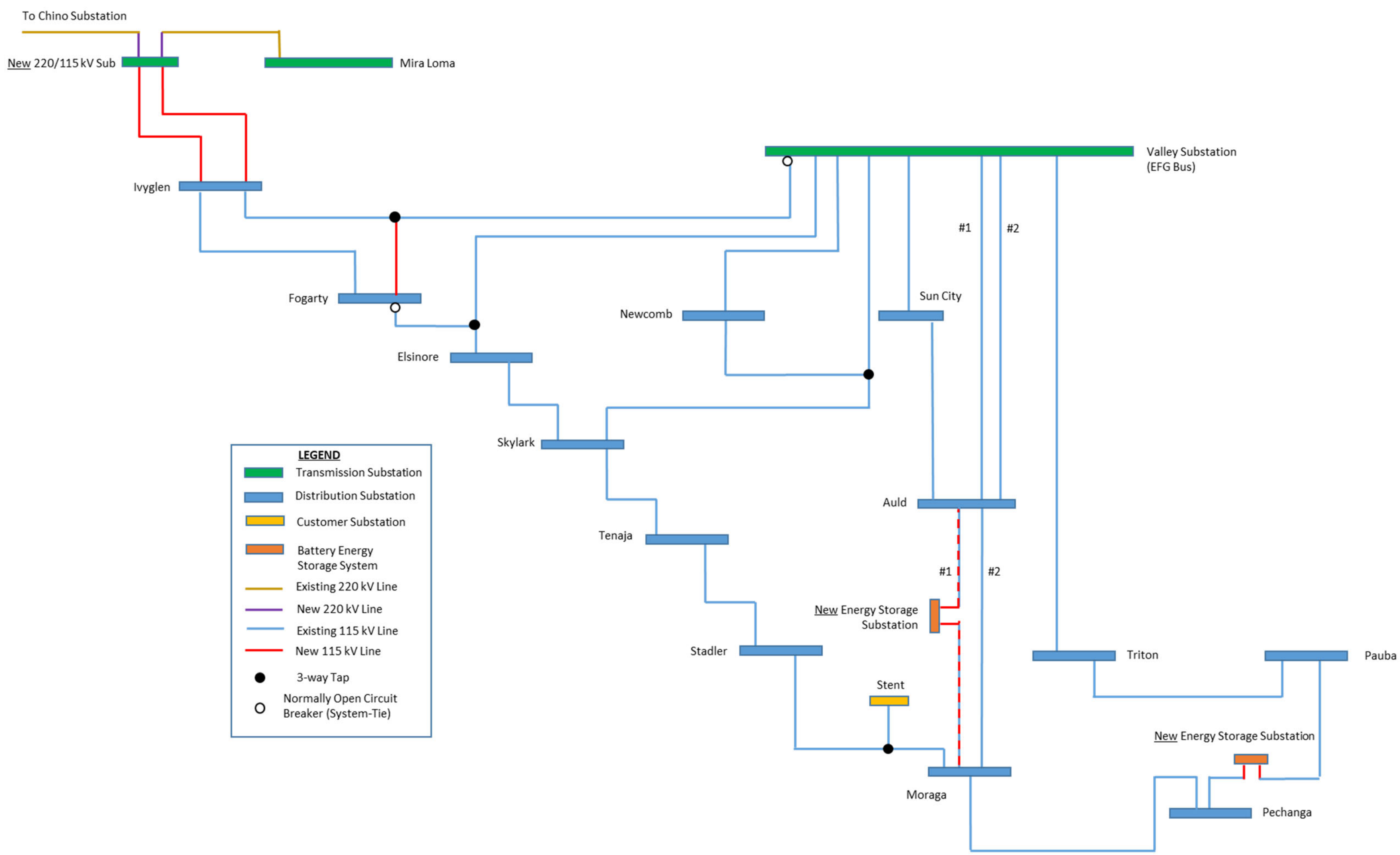
C.11.1 **System Solution Overview**

The Mira Loma alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system via construction of a new 220/115 kV substation and looping in the Mira Loma-Chino 220 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Ivyglen and Fogarty 115/12 kV distribution substations to the new 220/115 kV system. The existing 115 kV subtransmission lines serving Ivyglen and Fogarty substations would become two system-ties between the newly formed 220/115 kV Mira Loma System and the Valley South System. The system-ties would allow for the transfer of load from the new system back to the Valley South System (either or both Ivyglen and Fogarty Substations) as well as additional load transfer from the Valley South System to the new system (Elsinore Substation) as needed.

To further reduce load in the Valley South System, two new 115/12 kV substations with BESSs would be constructed near Pechanga and Auld Substations, which loop-in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.

C.11.2 **System Single Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-22 on the following page.



Schematic Representation. Not to scale.

Figure C-22. System One-Line Schematic of the Mira Loma and Centralized BESS in Valley South Alternative

C.11.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 220/115 kV substation (approximately 15-acre footprint)
- Construct a new 220 kV double-circuit transmission line segment to loop SCE's existing Chino-Mira Loma 220 kV transmission line into SCE's new 220/115 kV substation (approximately 130 feet)
- Construct a new 115 kV double-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation (approximately 21.6 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to tap SCE's future Valley-Ivyglen 115 kV subtransmission line to SCE's existing 115 kV Fogarty Substation (approximately 0.6 mile)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Construct two new 115/12 kV substations with BESSs (each with an approximately 9-acre footprint)
- Construct two new 115 kV subtransmission segments to loop the new 115 kV BESS locations into SCE's existing 115 kV subtransmission system

In total, this system alternative would require the construction of approximately 29.4 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided in the subsections that follow.

New 220/115 kV Substation

The Mira Loma and Centralized BESS in Valley South system alternative would involve the construction of a new, approximately 15-acre, 220/115 kV substation on a privately owned, approximately 27-acre, vacant parcel. The parcel is located north of Ontario Ranch Road, east of Haven Avenue, and west of Hamner Avenue in the City of Ontario. The parcel is rectangular in shape and is bounded by vacant land to the north, SCE's existing 220 kV Mira Loma Substation and vacant land to the east, vacant land to the south, and vacant land and industrial uses to the west. The vacant parcel has a residential land use designation, and an existing SCE transmission corridor crosses the southeast portion of the site. Vehicular access would likely be established from Ontario Ranch Road.

New 220 kV Double-Circuit Transmission Line

A new 220 kV double-circuit transmission line segment would be constructed between the existing Chino-Mira Loma 220 kV transmission line and SCE's new 220/115 kV substation. This approximately 130-foot segment would begin within SCE's existing transmission corridor, approximately 2,000 feet east of Haven Avenue, and extend south until reaching SCE's new 220/115 kV substation site.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line would be constructed, connecting SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation. This line would exit the new 220/115 kV substation site from the southerly portion of the property and travel east in an underground configuration for approximately 0.2 miles along Ontario Ranch Road. The line would pass under SCE's existing transmission line corridor and then transition to an overhead configuration, continuing on new structures along Ontario Ranch Road for approximately 0.5 miles until intersecting Hamner Road. The line would then extend south along Hamner Road and parallel to SCE's existing Mira Loma-Corona 66 kV subtransmission line for approximately 6.8 miles. Within this approximately 6.8-miles portion of the route, the line would exit the City of Ontario and enter the City of Eastvale at the intersection with Bellegrave Avenue. Within the City of Eastvale, the line would continue along Hamner Avenue, cross the Santa Ana River, and enter the City of Norco. Within the City of Norco, the line would continue south along Hamner Avenue until intersecting 1st Street. At this point, the line would extend west along 1st Street for approximately 0.5 miles until West Parkridge Avenue. At this intersection, the line would enter the City of Corona and continue generally south along North Lincoln Avenue for approximately 3.2 miles, paralleling the Chase-Corona-Databank 66 kV subtransmission line between Railroad Street and West Ontario Avenue. At the intersection with West Ontario Avenue, the line would extend east and continue paralleling SCE's existing Chase-Corona-Databank 66 kV subtransmission line for approximately 1.4 miles until the intersection with Magnolia Avenue. The line would continue along West Ontario Avenue for approximately 0.2 mile, then it would parallel SCE's existing Chase-Jefferson 66 kV subtransmission line between Kellogg Avenue and I-15 for approximately 1.7 miles. The line would continue along East Ontario Avenue, pass under I-15, and exit the City of Corona after approximately 0.2 miles at the intersection of East Ontario Avenue and State Street. The line would extend southeast for approximately 1.8 miles along East Ontario Avenue within Riverside County until the intersection of Cajalco Road. At this intersection, the line would extend southeast along Temescal Canyon Road, crossing the City of Corona for approximately 1.2 miles between Cajalco Road and Dos Lagos Drive. The line would then continue within Riverside County along Temescal Canyon Road for approximately 3.9 miles before crossing under I-15 and terminating at SCE's existing 115 kV Ivyglen Substation. This segment of the system alternative would be approximately 21.6 miles in length.

New 115 kV Single-Circuit Subtransmission Line

A new 115 kV single-circuit subtransmission line segment would be constructed to tap SCE's future Valley-Ivyglen 115 kV subtransmission line into SCE's existing 115 kV Fogarty Substation. The new line segment would begin along the future Valley-Ivyglen 115 kV subtransmission line's alignment, approximately 680 feet southeast of the intersection of Pierce Street and Baker Street in the City of Lake Elsinore. The new line segment would extend generally southwest and parallel to SCE's existing Valley-Elsinore-Fogarty 115 kV subtransmission line until terminating at SCE's existing 115 kV Fogarty Substation. This segment of the system alternative would be approximately 0.6 miles in length.

Reconductor Existing 115 kV Subtransmission Lines

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

BESS and 115 kV Loop-Ins

Pechanga BESS and Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the City of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

Auld BESS and Loop-In

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 24.6-acre, privately owned parcel in the City of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld-Moraga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Auld BESS.

C.11.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-23 on the following page.

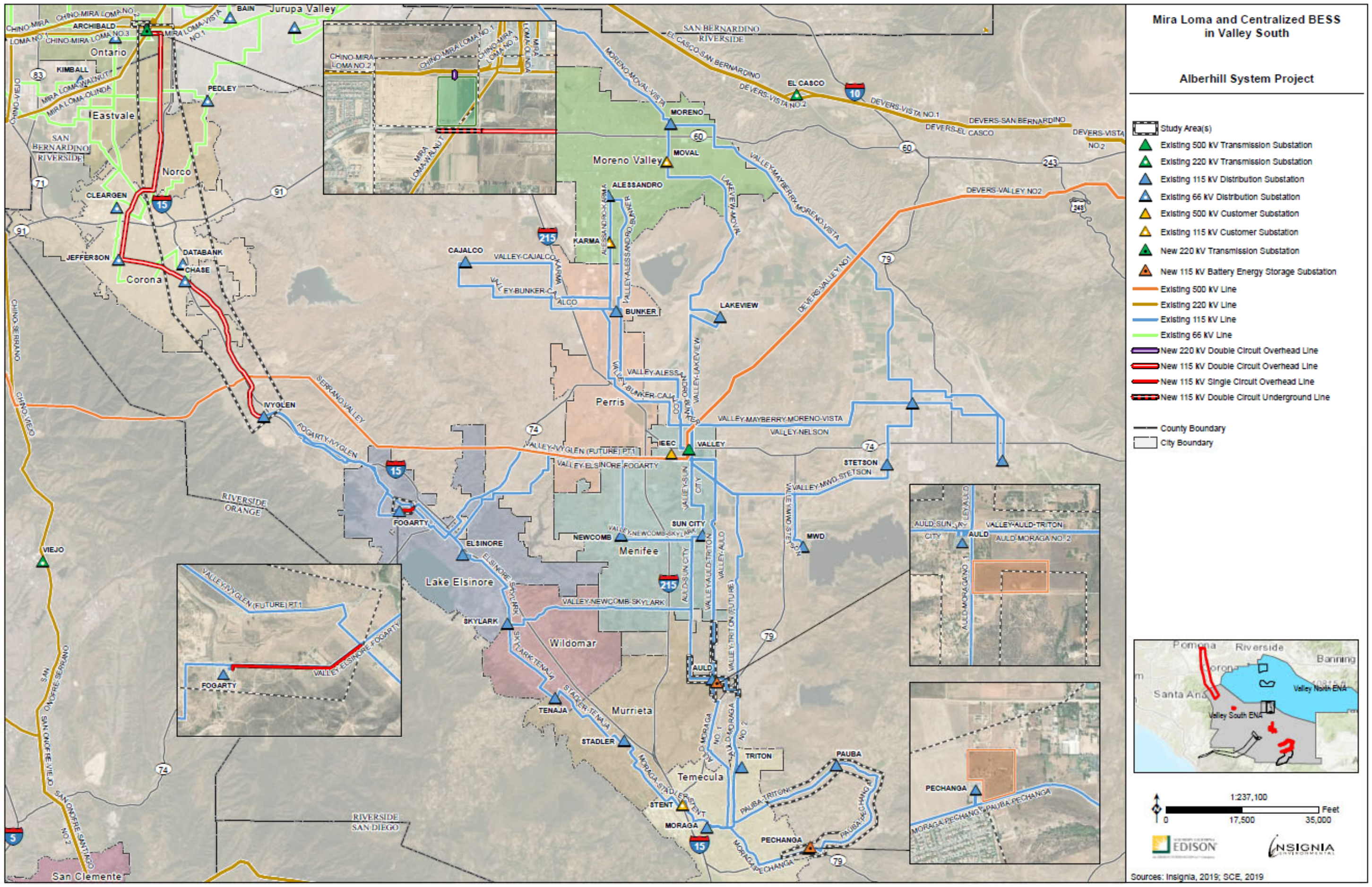


Figure C-23. Siting and Routing Map for the Mira Loma and Centralized BESS in Valley South Alternative[98]

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[98] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.11.5 **Project Implementation Scope**

Table C-24 summarizes the scope for this alternative.

Table C-24. Mira Loma and Centralized BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 220/115 kV Substation	
Electrical	New (3) position, (4) element 220 kV breaker-and-a-half switchrack to accommodate (2) transformers & (2) lines
	(2) 280 MVA, 220/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	220 and 115 kV line protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 115/12 kV Substation with BESS (adjacent to Auld Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV line protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 115/12 kV Substation with BESS (adjacent to Pechanga Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 220 kV Transmission Line	
Loop-in Chino-Mira Loma 220 kV Transmission Line to New 220/115 kV Substation	100 feet new overhead double-circuit

Scope	Detailed Scope Element
New 115 kV Subtransmission Lines	
Mira Loma-Ivyglen	21.6 miles (21.4 overhead double-circuit , 0.2 underground double-circuit)
Valley-Ivyglen to Fogarty	0.6 miles overhead single-circuit
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Mira Loma	(1) 220 kV line protection upgrade
Chino	(1) 220 kV line protection upgrade
Fogarty	Equip (1) 115 kV line position
Ivyglen	Remove No.3 capacitor from Position 1
	Equip (2) 115 kV line positions and (1) 115 kV line protection upgrade
Valley	(1) 115 kV line protection upgrade
Distribution	
Replace Existing Single-Circuit Overhead	Approximately 15,400 feet
Replace Existing Double-Circuit Overhead	Approximately 11,200 feet
Transmission Telecom	
Chino-Mira Loma 220 kV Line to New 220/115 Substation	100 feet overhead fiber optic cable
Mira Loma-Ivyglen	21.6 miles (21.4 overhead, 0.2 underground) fiber optic cable
Valley-Ivyglen to Fogarty	0.6 miles overhead fiber optic cable
Real Properties	
Mira Loma Substation D-C-02A	Fee Acquisition – (1) 26.78-Acre Parcel
Mira Loma-Ivyglen 115 kV Subtransmission Line	New Easement – (68) Parcels (10 miles, 30 ft. wide, 36.36 acres total)
Valley-Ivyglen to Fogarty 115 kV Subtransmission Line	New Easement – (10) Parcels (0.36 miles, 30 ft. wide, 1.31 acres total)
Pechanga BESS B-A-10	Fee Acquisition – (1) 16.9-Acre Parcel
Auld BESS A-C-04	Fee Acquisition – (1) 24.6-Acre Parcel
Mira Loma Laydown Yard	Lease – (1) 10-Acre Parcel for 92 months
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 220/115 kV Substation and BESS Locations	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-25 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-25. Battery Installations

Year	PVWatts Forecast		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
2036	66	195	2031	83	247	2026	99	299
2041	34	194	2036	48	303	2031	52	373
2046	9	62	2041	43	296	2036	61	463
-	-	-	2046	12	106	2041	54	427
-	-	-	-	-	-	2046	18	157
Total	109	451	Total	186	952	Total	284	1719

C.11.6 **Cost Estimate Detail**

Table C-26 below summarizes the costs for this alternative under the three load forecast used in the cost benefit analysis.

Table C-26. Mira Loma and Centralized BESS in Valley South Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	118	140	157
Substation Estimate	105	126	142
Owners Agent (10% of construction)	13	14	15
Corporate Security	6	6	6
Bulk Transmission	3	3	3
Subtransmission	101	101	101
Transmission Telecom	3	3	3
Distribution	4	4	4
IT Telecom	4	4	4
RP	27	27	27
Environmental	26	26	26
Subtotal Direct Cost	**326**	**348**	**365**
Subtotal Battery Cost	**301**	**603**	**1,129**
Uncertainty	293	445	700
Total with Uncertainty	**920**	**1,396**	**2,194**
Total Capex	**920**	**1,396**	**2,194**
Battery Revenue	**14**	**40**	**89**
PVRR	**448**	**560**	**601**

C.12 Valley South to Valley North and Centralized BESS in Valley South and Valley North

C.12.1 **System Solution Overview**

The Valley South to Valley North alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to SCE's existing Valley North 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed.

To further reduce load in the Valley South System, a new 115/12 kV substation with BESS would be installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line and a second BESS will be installed at Alessandro Substation to offset a portion of the load that is transferred from the Valley South to Valley North System.

C.12.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-24 and Figure C-25 on the following pages (Valley North portion and Valley South portion, respectively).

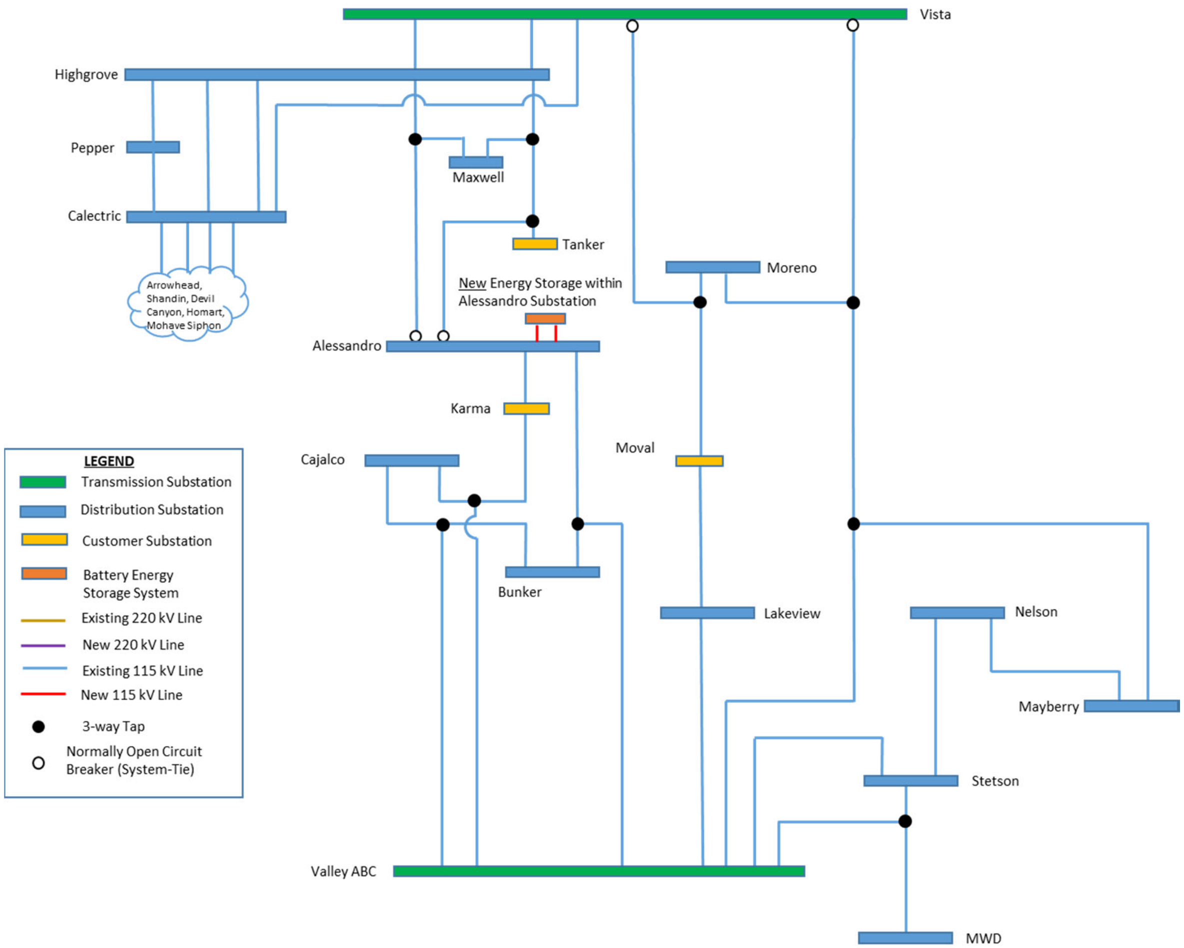

Figure C-24. System One-Line Schematic of the Valley South to Valley North and Centralized BESS in Valley South and Valley North Alternative (Valley North Portion)

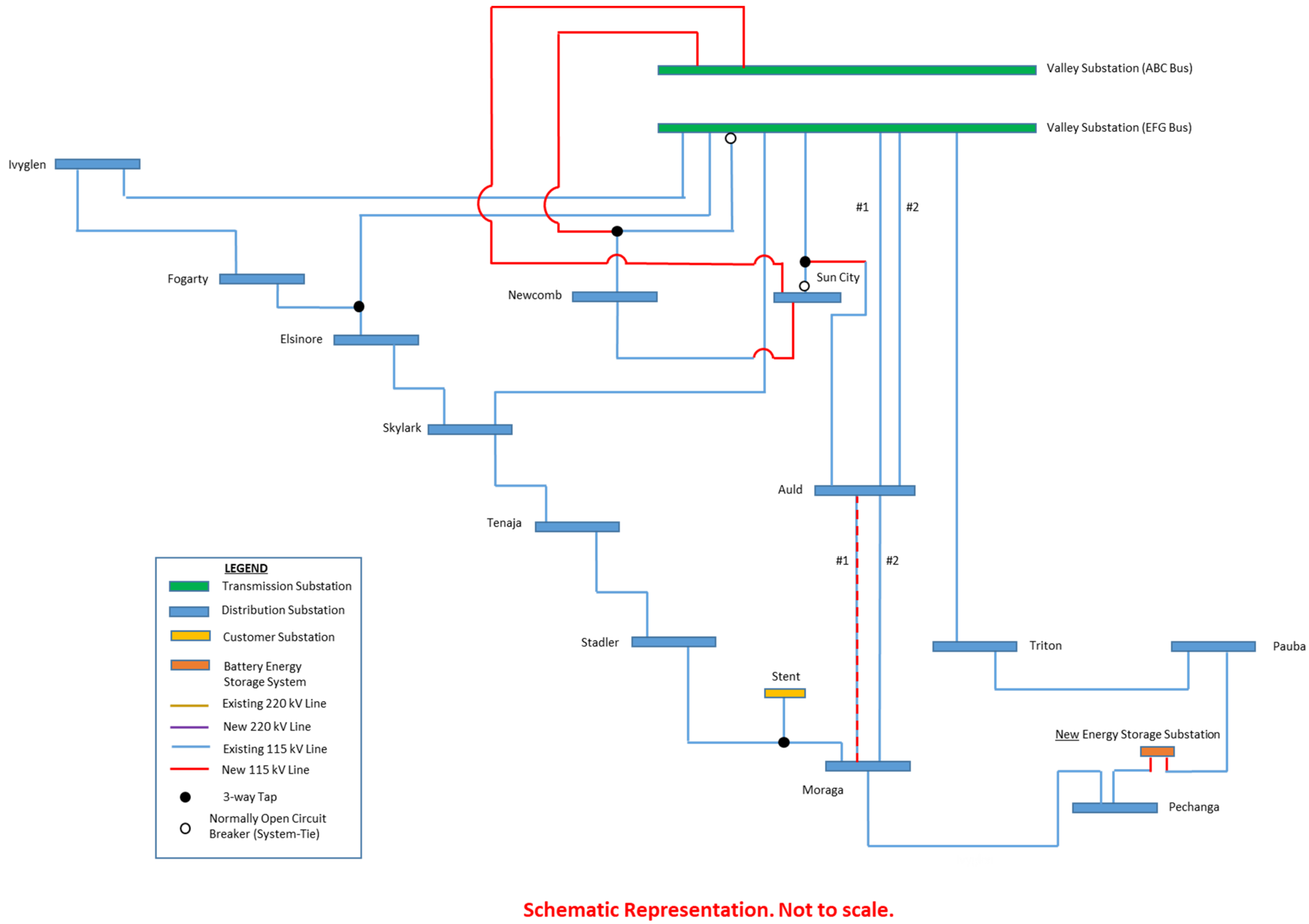

Figure C-25. System One-Line Schematic of the Valley South to Valley North and Centralized BESS in Valley South and Valley North Alternative (Valley South Portion)

C.12.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley and 115 kV Sun City Substations (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Construct one new 115/12 kV substation with BESS and add BESSs to an existing SCE substation
- Construct one new 115 kV subtransmission segment to loop the new BESS into SCE's existing subtransmission system

This system alternative would require the construction of approximately 13.1 miles of new 115 kV subtransmission line. A detailed description of each of these components is provided in the subsections that follow.

<u>New 115 kV Single-Circuit Subtransmission Lines</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld-Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Reconductor Existing 115 kV Subtransmission Lines

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

BESS and 115 kV Loop-Ins

Pechanga BESS and Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the City of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga

115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

Alessandro BESS

The 115 kV Alessandro BESS would be constructed within SCE's existing 115 kV Alessandro Substation in the City of Moreno Valley. The existing substation is located on an approximately 24.2-acre parcel at the intersection of John F Kennedy Drive and Kitching Street. This site is bounded by residential development to the north, east, and south; and residential development and a school to the west.

C.12.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-26 on the following page.

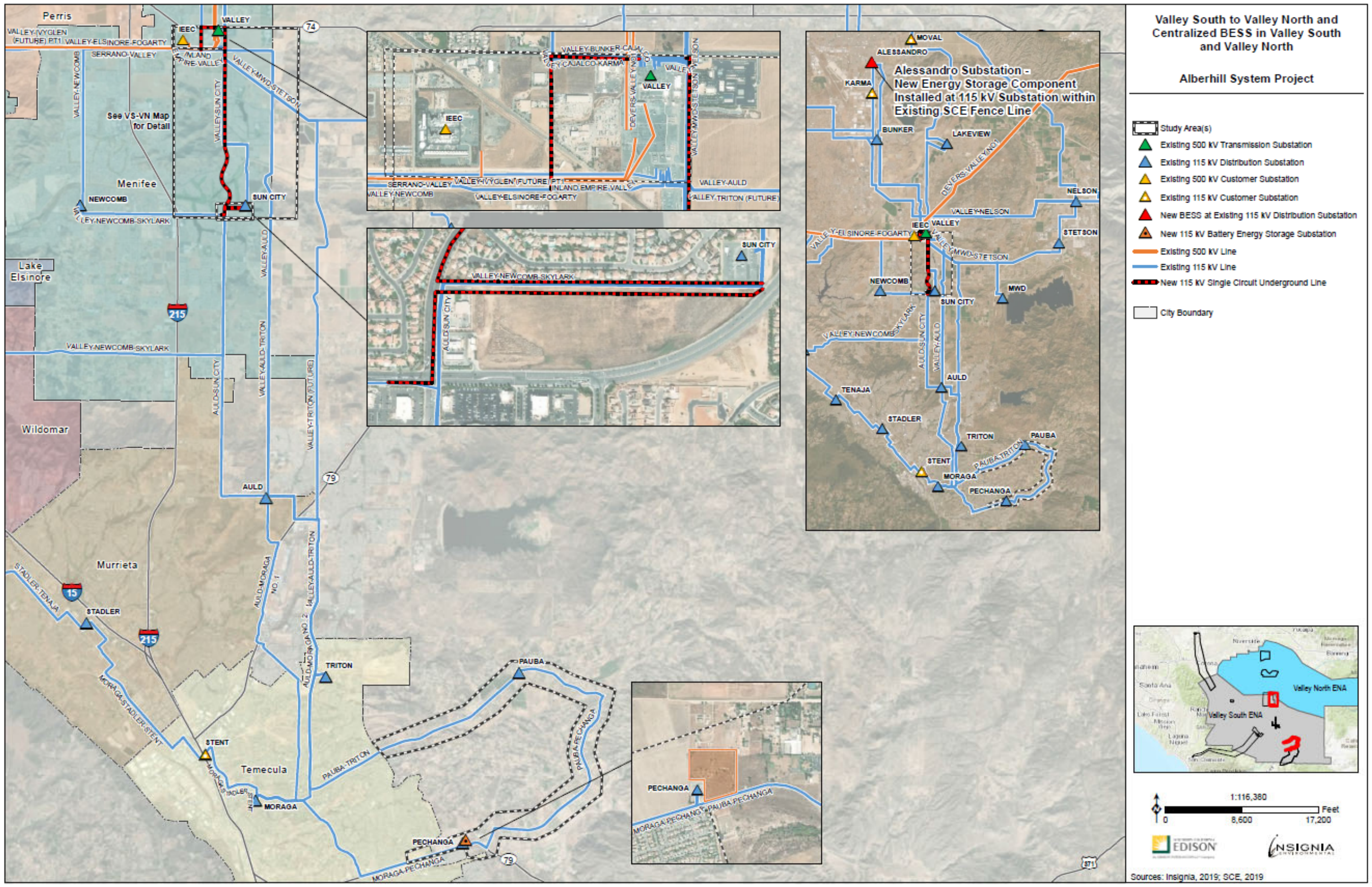

Figure C-26. Siting and Routing Map for the Valley South to Valley North and Centralized BESS in Valley South and Valley North Alternative[99]

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99 Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.12.5 **Project Implementation Scope**

Table C-26 summarizes the scope for this alternative.

Table C-26. Valley South to Valley North and Centralized BESS in Valley South and Valley North Scope Table

Scope	Detailed Scope Element
System Scope Elements	
BESS in Alessandro Substation**	
Electrical	Equip (3) 115 kV positions on the existing switchrack to accommodate (3) transformers
	(6) 28 MVA, 115/33kV transformers
	(3) new, (12) position 33 kV operating/transfer switchracks
	115 and 33 kV Line Protection
Civil	Foundations for all substation equipment
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	300 MW/ 1500 MWh
New 115/12 kV Substation with BESS (adjacent to Pechanga Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position, repurpose Position No. 2 for 115 kV Line with (1) line protection upgrade, and (1) line protection upgrade
Valley	Equip 115 kV Position 7 with (2) new 115 kV Lines, and (2) line protection upgrades on EFG Bus.
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 18,900 feet

Scope	Detailed Scope Element
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Real Properties	
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Pechanga BESS Location B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New BESS Locations	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-27 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-27. Battery Installations

Year	PVWatts Forecast		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
2040 (VS)	67	204	2037 (VN)	83	290	2030 (VN)	97	375
2045 (VS)	27	165	2042 (VN)	46	335	2035 (VN)	77	635
-	-	-	2043 (VS)	39	108	2036 (VS)	81	242
-	-	-	2046 (VS)	10	42	2040 (VN)	72	704
-	-	-	2046 (VN)	18	165	2041 (VS)	49	291
-	-	-	-	-	-	2045 (VN)	39	418
-	-	-	-	-	-	2046 (VS)	18	114
Total (VS)	94	369	Total (VN)	147	790	Total (VN)	285	2132
			Total (VS)	49	150	Total (VS)	148	647

C.12.6 **Cost Estimate Detail**

Table C-28 summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-28. Valley South to Valley North and Centralized BESS in Valley South and Valley North Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	40	89	116
Substation Estimate	34	80	106
Owners Agent (10% of construction)	6	9	10
Corporate Security	3	3	3
Bulk Transmission	n/a	n/a	n/a
Subtransmission	78	78	78
Transmission Telecom	2	2	2
Distribution	n/a	n/a	n/a
IT Telecom	2	2	2
RP	5	5	5
Environmental	18	18	18
Subtotal Direct Cost	**213**	**230**	**258**
Subtotal Battery Cost	**226**	**606**	**1,598**
Uncertainty	164	336	760
Total with Uncertainty	**572**	**1,172**	**2,616**
Total Capex	**572**	**1,172**	**2,616**
Battery Revenue	**7**	**20**	**88**
PVRR	**255**	**367**	**700**

C.13 Valley South to Valley North to Vista and Centralized BESS in Valley South

C.13.1 System Solution Overview

The Valley South to Valley North to Vista alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to the Valley North 500/115 kV System, and away from the Valley North 500/115 kV System to the Vista 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations from the Valley South to the Valley North System, and the Moreno 115/12 kV distribution substation to the Vista System. Subtransmission line construction and modifications in Valley South create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed. Subtransmission line construction and modifications in Valley North create two system-ties between the Valley North and Vista Systems. These system-tie lines would allow for the transfer of load from the Vista system back to the Valley North System (Moreno Substation) as well as additional load transfer from the Valley North System to the Vista System (Mayberry Substation) as needed.

To further reduce load in the Valley South System, a new 115/12 kV substation with BESS would be installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line.

C.13.2 System One-Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-27 and Figure C-28 on the following pages (Valley North and Valley South portions, respectively).

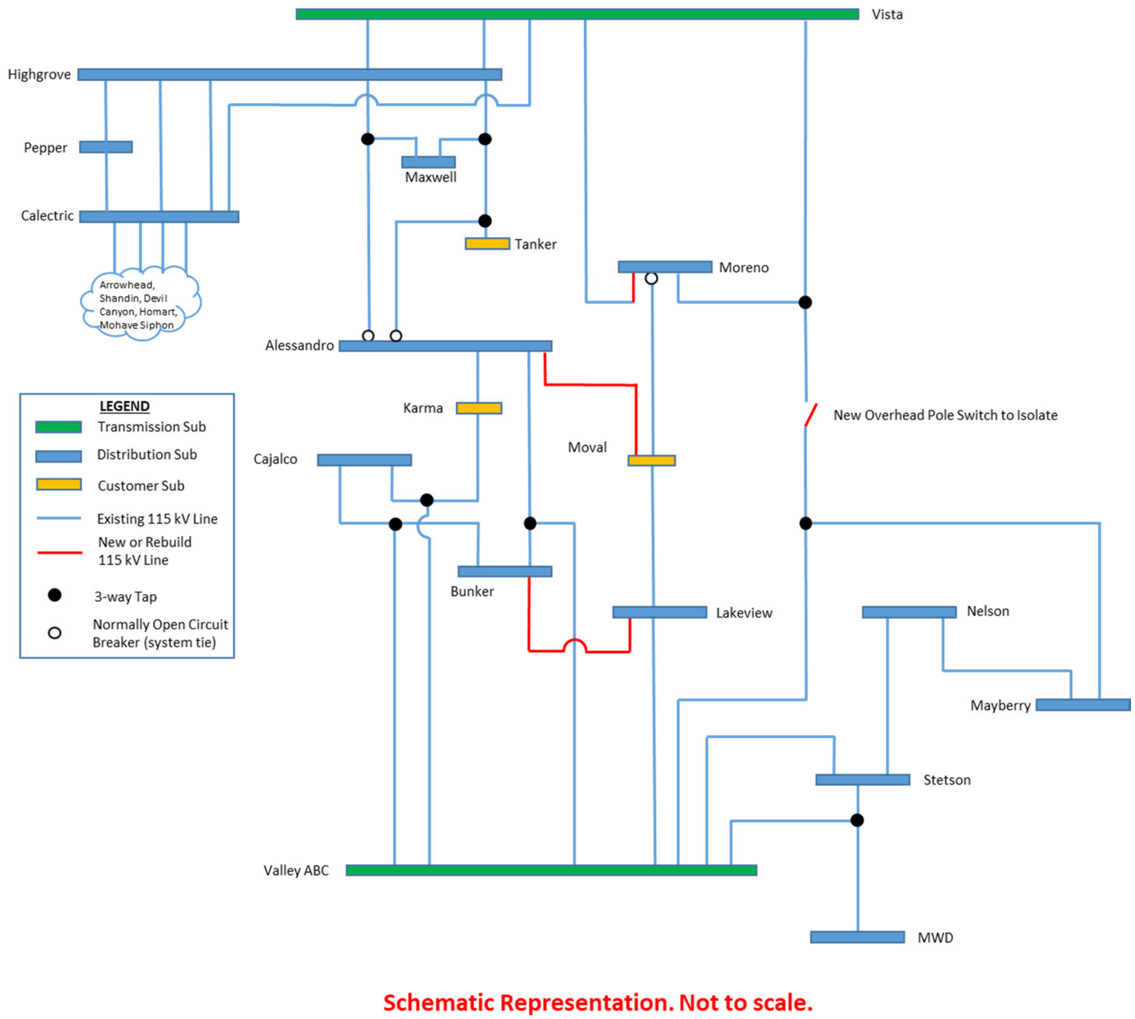

Figure C-27. System One-Line Schematic of the Valley South to Valley North to Vista and Centralized BESS in Valley South (Valley North Portion)

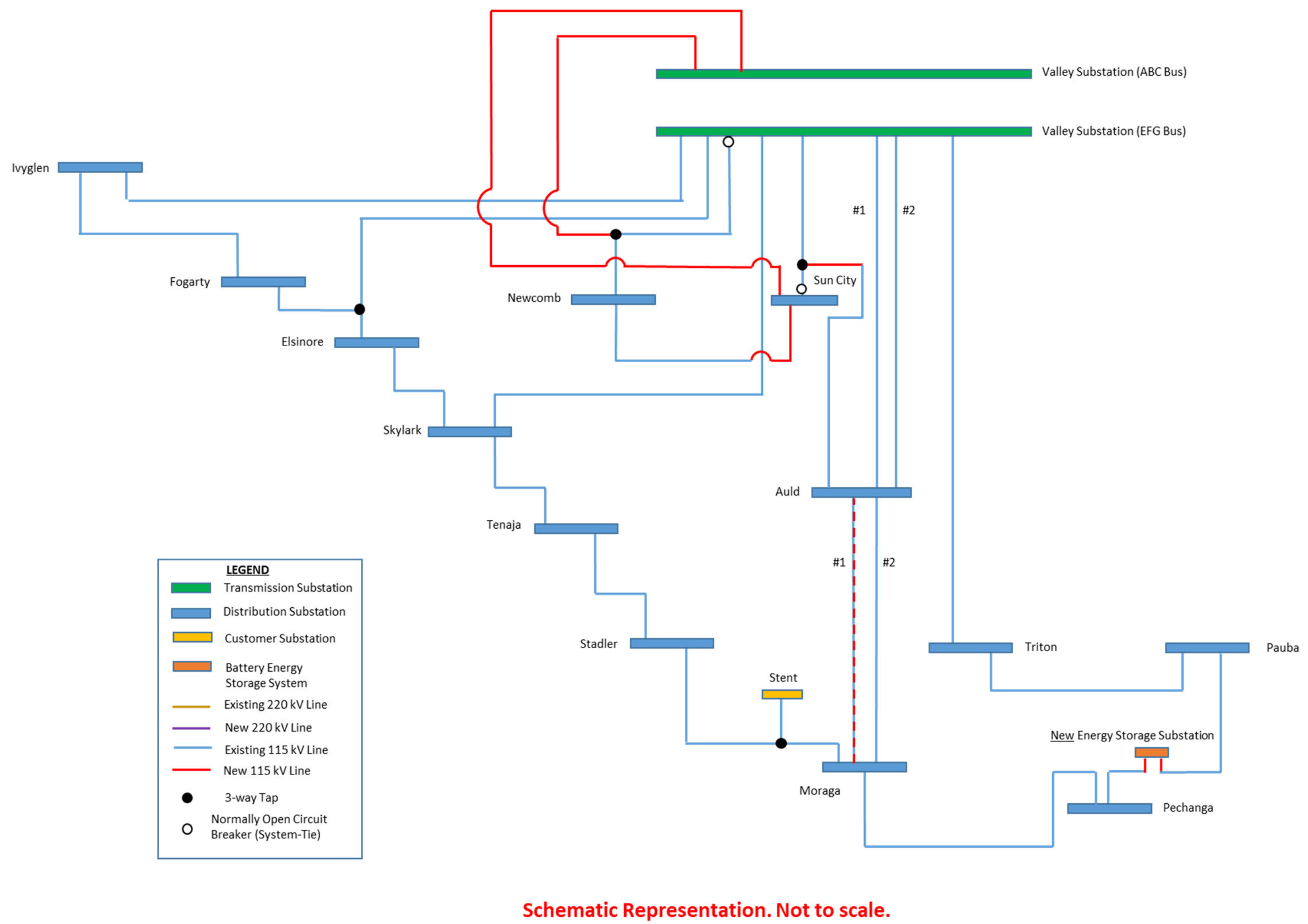

Figure C-28. System One-Line Schematic of the Valley South to Valley North to Vista and Centralized BESS in Valley South (Valley South Portion)

C.13.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE’s existing 500 kV Valley and 115 kV Sun City Substations (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE’s existing Valley-Newcomb 115 kV subtransmission line to SCE’s existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE’s existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE’s existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE’s existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE’s existing 115 kV Bunker and Lakeview Substations (approximately 6 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE’s existing 115 kV Alessandro and Moval Substations (approximately 4 miles)
- Double-circuit a segment of SCE’s existing 115 kV Moreno-Moval-Vista subtransmission line (approximately 0.1 mile)
- Construct one new 115/12 kV substation with BESS (approximately 9-acre footprint)
- Construct one new 115 kV subtransmission segment to loop the new 115 kV BESS into SCE’s existing 115 kV subtransmission system

This system alternative would require the construction of approximately 15.9 miles of new 115 kV subtransmission line and the modification of approximately 7.3 miles of existing 115 kV subtransmission line. This system alternative totals approximately 23.2 miles. A detailed description of each of these components is provided in the subsections that follow.

<u>New 115 kV Single-Circuit Subtransmission Lines</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE’s existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit SCE’s existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend approximately 3.9 miles south along Menifee Road until reaching SCE’s existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east and parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 until reaching SCE’s existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west and parallel to SCE's existing Auld-Sun City 115 kV subtransmission line until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west for approximately 350 feet along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line until terminating at an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Bunker Substation to Lakeview Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Bunker Substation in the City of Perris and 115 kV Lakeview Substation in Riverside County. From SCE's existing 115 kV Bunker Substation, the line would extend south on Wilson Avenue on new structures for approximately 0.4 miles until the intersection with Placentia Avenue. At this intersection, the line would extend east on Placentia Avenue for approximately 0.4 mile, then turn south for approximately 0.3 miles and travel parallel to a dry creek bed until the intersection with Water Avenue. At the intersection with Water Avenue, the line would leave the City of Perris and extend east for approximately 0.8 miles until the intersection with Bradley Road. The line would then continue east across vacant and agricultural lands for approximately 2.1 miles until intersecting SCE's existing Valley-Lakeview 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Valley-Lakeview 115 kV subtransmission line for approximately 2 miles, then extend north until terminating at SCE's existing 115 kV Lakeview Substation. The current route extends north, southeast along 11th Street, and northeast along an unpaved access road before arriving at SCE's existing 115 kV Lakeview Substation. This segment of the system alternative would be approximately 6 miles in length.

Alessandro Substation to Moval Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Alessandro and Moval Substations in the City of Moreno Valley. The new line would exit SCE’s existing 115 kV Alessandro Substation in an underground configuration and extend north for approximately 350 feet along Kitching Street until intersecting John F Kennedy Drive. At this intersection, the line would transition to an overhead configuration on new structures and extend east along John F Kennedy Drive for approximately 0.5 miles until the intersection with Lasselle Street. The line would then extend north on Lasselle Street for approximately 1 miles until the intersection with Alessandro Boulevard, where the line would extend east for approximately 2 miles until intersecting Moreno Beach Drive and SCE’s existing Lakeview-Moval 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Lakeview-Moval 115 kV subtransmission line for approximately 0.5 miles until terminating at SCE’s existing 115 kV Moval Substation. The current route extends north along Moreno Beach Drive until reaching SCE’s existing 115 kV Moval Substation, approximately 0.1 miles south of the intersection of Moreno Beach Drive and Cottonwood Avenue. This segment of the system alternative would be approximately 4 miles in length.

Double-Circuit Existing 115 kV Subtransmission Line

SCE currently operates an existing, single-circuit Moreno-Moval-Vista 115 kV subtransmission line between SCE’s existing 115 kV Moreno, Moval, and Vista Substations. An approximately 0.1-miles segment of this line within the City of Moreno Valley would be converted from a single-circuit to double-circuit configuration. This segment would begin at the intersection of Ironwood Avenue and Pettit Street and extend east before turning north and entering SCE’s existing 115 kV Moreno Substation.

Reconductor Existing 115 kV Subtransmission Lines

SCE’s existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE’s existing 115 kV Auld and Moraga Substations. This component would begin at SCE’s existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE’s existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

BESS and 115 kV Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE’s existing 115 kV Pechanga Substation in the City of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE’s existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

C.13.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-29 on the following page.

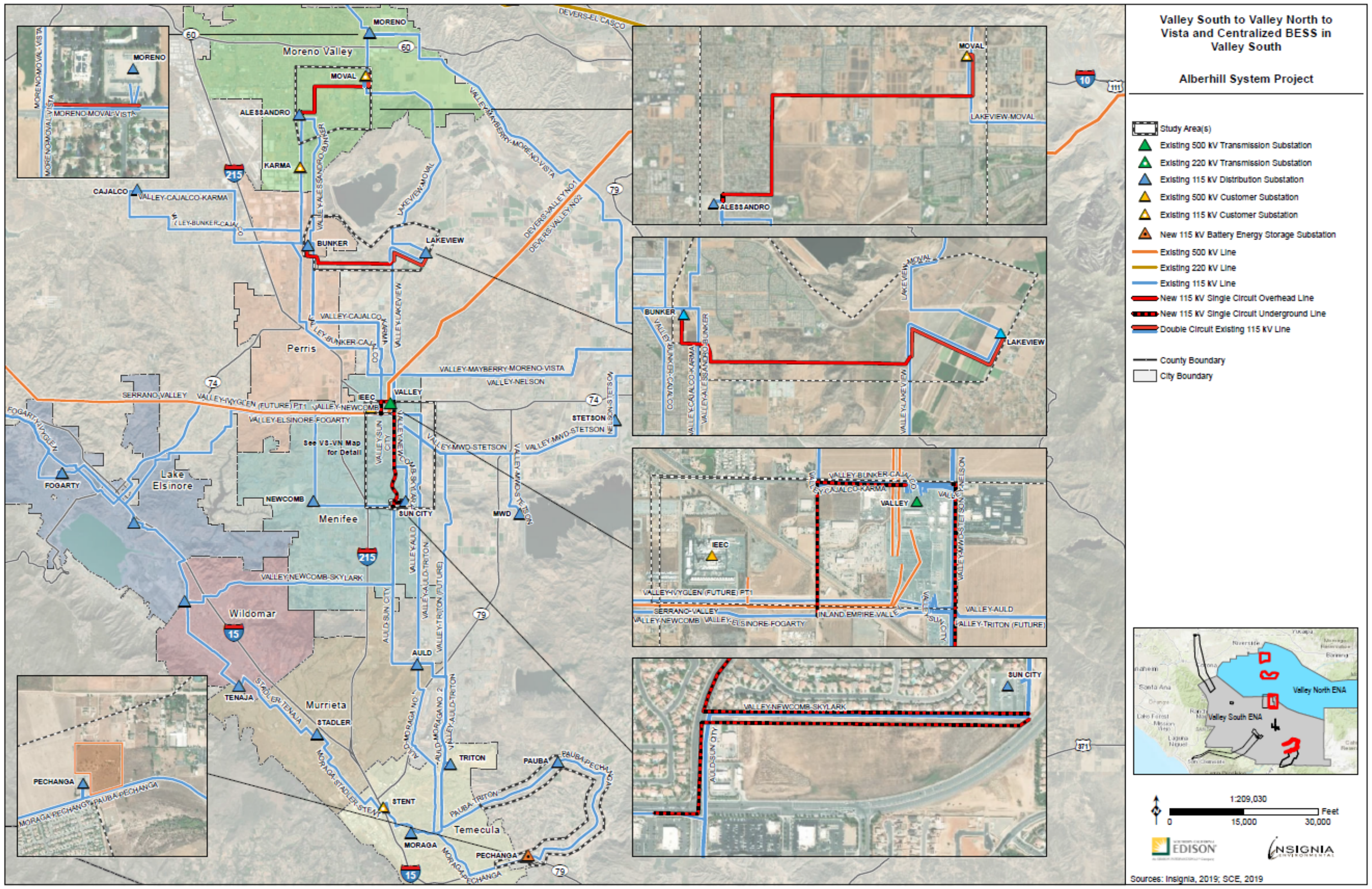

Figure C-29. Siting and Routing Map for the Valley South to Valley North to Vista and Centralized BESS in Valley South Alternative[100]

[100] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.13.5 **Project Implementation Scope**

Table C-28 summarizes the scope for this alternative.

Table C-28. Valley South to Valley North to Vista and Centralized BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 115/12 kV Substation with BESS (adjacent to Pechanga Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Sun City	7.7 miles overhead reconductor existing
Alessandro-Moval	4 miles (3.5 overhead single-circuit , 0.1 underground single-circuit , and 0.4 overhead double-circuit existing)
Bunker-Lakeview	6 miles (3.9 overhead single-circuit , 2.1 overhead double-circuit existing)
Moreno-Moval	0.1 miles overhead double-circuit existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position , repurpose Position No. 2 for 115 kV Line with (1) line protection upgrade, and (1) line protection upgrade
Valley ABC	Equip 115 kV Position 7 with (2) new 115 kV Lines, and (2) line protection upgrades on Valley South Switchrack.
Moreno	(1) 115 kV line position
Moval	(2) 115 kV line position & (1) line protection upgrade
Bunker	Equip (1) 115 kV line position
Lakeview	Equip (1) 115 kV line position

Scope	Detailed Scope Element
Alessandro	Build and equip (1) 115 kV line position
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 19,200 feet
Replace Existing Single-Circuit Overhead	Approximately 12,800 feet
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Alessandro-Moval	4 miles (3.9 overhead, 0.1 underground) fiber optic cable
Bunker-Lakeview	6. miles overhead fiber optic cable
Real Properties	
Alessandro-Moval	New Easement – (20) Parcels (1 mile, 30 ft. wide, 9.09 acres total)
Bunker-Lakeview	New Easement – (45) Parcels (5 miles, 30 ft. wide, 18.18 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Pechanga BESS Location B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New BESS Locations	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-29 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-29. Battery Installations

Year	PVWatts Forecast[1]		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
-	-	-	2043	39	108	2036	81	242
-	-	-	2046	10	42	2041	49	291
-	-	-	-	-	-	2046	18	114
-	-	-	Total	49	150	Total	148	647

Note:

1. The PVWatts forecast does not necessitate a need for batteries to meet N-0 capacity requirements, i.e., the conventional scope of this alternative alone mitigates all N-0 transformer capacity overloads through the 30 -year horizon of the cost benefit analysis.

C.13.6 **Cost Estimate Detail**

Table C-30 below summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-30. Valley South to Valley North to Vista and Centralized BESS in Valley South Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast[1]	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	17	53	68
Substation Estimate	8	44	58
Owners Agent (10% of construction)	8	9	10
Corporate Security	n/a	2	2
Bulk Transmission	n/a	n/a	n/a
Subtransmission	109	109	109
Transmission Telecom	3	3	3
Distribution	3	1	1
IT Telecom	2	2	2
RP	18	18	18
Environmental	29	29	29
Subtotal Direct Cost	**213**	**250**	**265**
Subtotal Battery Cost	**n/a**	**101**	**422**
Uncertainty	95	153	298
Total with Uncertainty	**307**	**505**	**986**
Total Capex	**307**	**505**	**986**
Battery Revenue	**n/a**	**2**	**18**
PVRR	**269**	**289**	**404**

Note:

1. The PVWatts forecast does not necessitate a need for batteries. The scope for this alternative under the PVWatts forecast is identical to the VS-VN-Vista alternative.

D Appendix – Uncertainty Scoring

The uncertainty scoring details for the Alberhill System Project and all project alternatives is provided in Table D-1. The impact of each uncertainty category on project schedule and budget was scored using a low, medium and high scale (low being a 1, medium being a 3, and high being a 5). Each uncertainty category was characterized as having a low, medium, or high (1, 3, or 5, respectively) impact on project schedule and budget. For each alternative, the likelihood that a specific uncertainty category would apply to that alternative was also scored on a not applicable, low, medium, or high basis (0, 1, 3, or 5, respectively). The uncertainty impact score was multiplied by each alternative's uncertainty likelihood score. This result for each uncertainty category was summed together for all alternatives to establish the final uncertainty score of the alternative.

Table D-1 – Uncertainty Scoring

Uncertainty Categories	Impact	Alberhill	SDG&E	SCE Orange County	Menifee	Mira Loma	Valley South to Valley North	Valley South to Valley North to Vista	Centralized BESS in Valley South	Valley North to Valley South and Distributed BESS in Valley South	SDGE and Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South
General Project														
Site and Route Local Public Opposition (Delay)	5	1	5	3	5	5	5	5	1	1	5	5	5	5
Other Local Development Activities Impact Site or Route (Delay)	3	3	5	3	3	5	3	3	1	3	5	5	3	3
Material Delays	1	1	3	3	5	3	3	3	5	5	5	5	5	5
Nesting Birds	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Agency Permitting Delays	5	3	5	5	3	3	3	3	3	3	5	3	3	3
Labor Market Conditions	3	3	5	5	3	5	3	3	1	3	5	5	3	3
Subtotal		48	92	76	72	82	70	70	40	52	94	84	72	72
Transmission/Subtransmission														
Property Acquisition	5	1	1	5	3	5	3	5	1	1	1	5	3	5
Cultural Resources	3	1	5	5	3	3	3	3	3	3	5	3	3	3
Biological Resources	3	1	5	5	3	3	3	3	3	3	5	3	3	3
Unknown Underground Conditions	3	1	3	3	5	5	5	5	3	5	3	5	5	5
Lack of Geotechnical Data/Design	3	3	3	5	3	3	3	3	3	3	3	3	3	3
Required Undergrounding	5	1	5	3	5	5	5	5	1	5	5	5	5	5
Outage Constraints Due to Existing Facilities	3	5	5	5	5	5	3	3	1	1	5	5	3	3
High Fire Areas (Stop Work)	3	3	5	1	3	1	3	3	5	3	5	1	3	3
Future Requirement for Subtransmission Covered Conductor	3	3	1	1	1	1	1	1	1	1	1	1	1	1
Uncertainty in Distribution Scope Due to Lack of Design	3	1	3	3	3	3	3	3	1	1	3	3	1	3
Change in Standards	1	3	3	3	3	3	3	3	3	3	3	3	3	3
Tariff/Commodity Material Cost Changes	3	1	1	1	1	1	1	1	1	1	1	1	1	1
Transmission Access Roads	5	1	3	3	0	0	0	0	0	0	3	0	0	0
Subtotal		75	141	145	124	128	118	128	76	96	141	128	112	128
Substation														
Cultural Resources	3	1	5	5	3	3	0	0	5	1	5	3	5	5
Biological Resources	3	1	5	5	3	3	0	0	5	1	5	3	5	5
Unknown Underground Conditions	3	1	1	1	3	5	0	0	1	1	1	5	1	1
Lack of Geotechnical Data/Design	3	3	3	3	3	3	0	0	3	1	3	3	3	3
Change in Standards	1	3	3	3	3	3	0	0	3	3	3	3	3	3
Equipment Tariffs (Substation)	3	1	1	1	1	1	0	0	1	1	1	1	1	1
Ground Grid	1	3	3	3	3	3	0	0	3	0	3	3	3	3

Table D-1 – Uncertainty Scoring

Uncertainty Categories	Impact	Alberhill	SDG&E	SCE Orange County	Menifee	Mira Loma	Valley South to Valley North	Valley South to Valley North to Vista	Centralized BESS in Valley South	Valley North to Valley South and Distributed BESS in Valley South	SDGE and Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South
Change in Corporate Security Scope	1	3	3	3	3	3	0	0	3	0	3	3	3	3
Subtotal		30	54	54	48	54	0	0	54	18	54	54	54	54
Battery (Specific)														
Hazardous Material disposal	1	0	0	0	0	0	0	0	3	3	3	3	3	3
Additional Fire Risk Modification Costs	1	0	0	0	0	0	0	0	5	5	5	5	5	5
Assumed Price Decline Not Realized	3	0	0	0	0	0	0	0	1	1	1	1	1	1
Subtotal		0	0	0	0	0	0	0	11	11	11	11	11	11
Total Uncertainty Score		**153**	**287**	**275**	**244**	**264**	**188**	**198**	**181**	**177**	**300**	**277**	**249**	**265**
Total Uncertainty Costs		**26%**	**48%**	**46%**	**41%**	**44%**	**32%**	**33%**	**31%**	**30%**	**50%**	**46%**	**42%**	**44%**

EXHIBIT C-2 (SECOND AMENDED) REDLINE

Alberhill System Project

Data Request Item C – Planning Study

ED-Alberhill-SCE-JWS-4: Item C

Revision ~~2~~2.1 (Second Amended Motion)

~~January~~ June 16~~29~~, 2021

Revision Summary

Revision 2.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This Second Amended Motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 2

Revision Date: January 29, 2021

Summary of Revisions:

This revision corrects errors identified by Southern California Edison (SCE) in the cost-benefit analysis results reported in Section 8 of this Planning Study. Specifically:

1. SCE identified errors in calculated probabilities of coincidental line outages and specific system loading conditions that would result in unserved customer load. As a result, the initial analysis substantially overstated the monetization of the Flex-1 alternative performance metric. The Flex-1 metric addresses load at risk of being unserved when N-2[1] line outages occur. The previous version of the analysis also considered N-1-1[2] outages. These N-1-1 outages are no longer considered in order to simplify the analysis and due to their very low impact on results when applying the updated probabilities.
2. SCE identified errors in the application of the SCE Value of Service (VoS) Study in assigning a monetary value to unserved customer load.
    a. The original analysis incorrectly weighted the monetization value based on the number of customers in each customer class as a fraction of the total customer count. This contrasts with the correct approach of valuing unserved energy based on the amount of electrical demand in each customer class as a fraction to the total amount of electrical demand served. As a result, the monetized value of the metrics was substantially increased in the current revision and is more representative of the cost impact of outages.
    b. The original analysis did not reflect SCE's practice to minimize the impact of an extended outage to any single set of customers (e.g., a distribution circuit or distribution substation), where practical, by periodically rolling the outages throughout the system. As a result, a one-hour outage monetization rate in the

[1] N-2 outages are associated with a single event causing two system elements (in this case lines) to be out of service at the same time.

[2] N-1-1 outages are associated with one system element being out of service (a planned or unplanned outage) followed by an unplanned outage for a second element.

VoS Study is now applied for each hour of the period during which load would be unserved, rather than assuming the entire duration of an outage would be experienced by a smaller group of customers, as was the case in the original analysis. This is the case for all metrics other than the Flex 2-1 metric where system operators would not have the flexibility to roll outages among customers due to the large amount of load at risk of being unserved in this metric. In this case, a lesser value, the average of one-hour and 24-hour outage monetization rates, is applied.

c. SCE identified an error that overstated the monetization rate for commercial and industrial (C&I) customers when the small/medium business (SMB) customers were combined with C&I customers as a single customer class. The costs of outages for residential, C&I, and SMB customer classes are now calculated individually at their correct individual outage cost rates.

The net effect of correcting the errors in application of the VoS Study is an increase in the monetized value of each MWh of projected interruption of service to customers, partially offsetting the probability weighting error identified above.

3. The Flex 2-1 and Flex 2-2 metrics were modified to no longer constrain the event that drives the impact of these metrics to occur at peak summer load conditions. This is consistent with the approach for other metrics, in that the probability weighting in the monetization reflects the random timing of occurrence of such an event with loading conditions varying throughout the year. This change reduces the monetized value of these benefits; but this reduction is offset in part by the change in the application of the VoS study described above. Additionally, the Flex 2-2 metric was modified to reflect a more realistic scenario in which only a single transformer would be left to serve the Valley South System load.

Other less significant changes to the Planning Study and supporting analysis were also made to clarify, simplify, or correct some areas of the analysis and/or its description. These areas were identified as a result of additional independent SCE internal reviews performed after identifying the errors described above and are summarized below:

1. For clarity, the non-monetized Expected Energy Not Served (EENS) metrics (EENS (N-0) and EENS (N-1)) metrics used in the original Planning Study and supporting analysis are now named Load at Risk (LAR). The term EENS might imply that the metric is probability weighted but probabilities are not assigned in the analysis until the metrics are monetized. Monetized values are still designated as EENS because probabilities have been assigned.
2. Project scope and associated costs have been added to several alternatives to correct N-1 line capacity violations that occur within the first ten years of the project planning horizon. These line violations are projected to occur as a result of increased load growth in the system in the event no project is implemented. For some alternatives, the need to correct the line violations is accelerated by changes in the system design of the respective alternative and in other cases the need is delayed or eliminated. These line violations were previously identified and discussed extensively in this Planning Study; however,

rather than including the associated scope and cost (to mitigate these violations) in the cost-benefit analysis, the impact of the line violations was previously reflected as reduced system benefits for the affected alternatives. The affected alternatives include all alternatives that transfer substations in the northern part of the Valley South System (Mira Loma, Menifee and all the alternatives that transfer load from Valley South to Valley North). The overall impact of this change to the cost-benefit analysis is minor because the cost of addressing the line violation is not large relative to the overall project scope, and the cost is partially offset by an increase in benefits due to correcting the line violations.

3. The market participation revenues for alternatives that include Battery Energy Storage Systems (BESS) were modified to include Resource Adequacy[3] payments for the eight months of the year where the BESS would not be dedicated to the system reliability need. This primarily affects the Centralized BESS alternative because the value is not significant for other alternatives due to the smaller quantity of batteries and the discounting associated with their later addition. The change does not significantly affect the cost-benefit analysis performance of the Centralized BESS alternative relative to other alternatives.
4. The timing of Operations and Maintenance costs for all alternatives is now correctly applied beginning at the project in-service date, as opposed to the project need date, at which it was previously applied. This change results in a minor decrease in the cost (Present Value Revenue Requirement or PVRR) for each alternative and does not significantly affect the relative cost-benefit analysis performance of alternatives.
5. The assumed start of construction for ASP was delayed by 18 months in this revision of the analysis to be consistent with all other alternatives. Previously the construction start date was in 2021, which is not realistic. The earlier start date negatively impacted the ASP relative to other alternatives; because, while its costs were incurred earlier, its benefits were not accelerated relative to other alternatives. Now all alternatives have a common set of assumptions – consistently accruing benefits at the project need date (2022)[4] and entering construction in 2023. The earlier construction spend for ASP in the previous version of the analysis increased ASP costs relative to other alternatives because the costs of other alternatives were discounted more heavily in the PVRR calculation due to their later construction start dates. The assumption on start of benefits has not changed in this version of the planning study. The overall goal of the analysis continues to be the consistent treatment of alternatives with respect to timing of costs and benefits so that the analysis reflects the true system performance of alternatives without being influenced by the large swings in results that could occur based on subjective judgments of the likely relative timing at which cost and benefits might actually accrue.

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[3] Resource adequacy payments reflect the market value of capacity added to the system by the BESS additions. In accordance with current market participation rules, this capacity value is credited only in months when the capacity is not likely required to satisfy a system reliability need due to a shortage in transformation capacity.

[4] Benefits are started on the need date rather than in-service date for all alternatives to maintain consistency among the alternatives, to simplify the analysis and to ensure that the near-term load forecast has a more dominant impact on the relative performance of the alternatives.

6. For clarity, SAIDI (System Average Interruption Index), SAIFI (System Average Interruption Frequency Index), and CAIDI (Customer Average Interruption Duration Index) metrics have been removed from the analysis. These metrics were calculated directly from LAR values, so they do not provide unique insight on the relative performance of system alternatives. Additionally, they were calculated based on a different base customer value than SAIDI, SAIFI, and CAIDI values reported by SCE in other supplemental analysis submittals[5] by SCE and would cause confusion if these data are compared among these submittals.
7. Other minor editorial corrections and clarifications.

Revision 1

Revision Date: May 6, 2020

Summary of Revisions:

Minor change to address an error in a data point in Figure 5-1.

[5] See A.09-09-022 CPUC-JWS-2 Q.01e and A.09-09-022 CPUC-JWS-2 Q.01d.

1.0 Executive Summary

Abstract

In Decision (D.) 18-08-026 for the Alberhill System Project (ASP) proceeding, the California Public Utilities Commission (CPUC) took no action on the ASP and directed Southern California Edison (SCE) to supplement the existing record with specific additional analyses. These additional analyses include, in part, this planning study that supports the project need and includes applicable planning criteria and reliability standards.

In considering both the need for a project and comparing a wide range of project alternatives, this planning study:

- provides historical context on the evaluation of the Valley South System;
- compares its configuration to other SCE subtransmission systems;
- summarizes the basis for forecasted load;
- addresses compliance with project objectives, system planning criteria, and reliability standards;
- applies forward-looking system performance metrics to assess effectiveness of alternatives in meeting project objectives;
- documents an objective cost/benefit analysis based on impact to customers; and
- considers a range of monetized and non-monetized risks.

This planning study confirms the need for a project and more specifically reinforces selecting a comprehensive solution for the Valley South System that addresses the transformer capacity shortfall, forecast for 2022, and provides adequate system tie-lines to another system in order to improve reliability and resiliency. Further, the planning study supports the ASP as SCE's recommended solution to address the defined objectives for the project.

System Background and Needs

The San Jacinto region houses the Valley System, made up of the Valley North and Valley South Systems combined, and serves approximately 325,000 metered customers and provides electricity to approximately 1,000,000 people. The Valley South System, which is the focus of this Planning Study, serves approximately 560,000 people, including nearly 6,000 critical care customers, over approximately 380 square miles in southwestern Riverside County. The Valley South System is served by the Valley Substation, which is unique within SCE's electric system in that it is the only substation that interfaces with the California Independent System Operator (CAISO)-controlled bulk electric system at 500/115 kilovolts (kV) and then directly serves 115/12 kV distribution substation load. The Valley Substation has been constructed to its ultimate system design capacity (2,240 megavolt-amperes or MVA with 1,120 MVA serving each of the Valley North and Valley South Systems respectively) and the Valley South System has demonstrated peak loading values that result in a 99.9% utilization[6] during peak loading conditions. Thus, even very modest continued load growth will negatively impact the ability of SCE to adequately serve the Valley South System. Further, the Valley South System is the only subtransmission system within SCE's entire territory (among its 56 separate subtransmission systems) that operates with zero tie-lines to other systems. The lack of system tie-lines results in an isolated system which negatively impacts the reliability and resiliency of the system due to the inability to transfer load during typically planned-for system contingency events and unplanned outages, including high-impact, low-probability events[7]. The combination of a very high utilization percentage and no system tie-lines requires operators to implement a pre-emptive temporary mitigation measure[8] by placing in service an installed spare transformer at Valley Substation during periods of high demand. This is the only system in SCE's territory that requires this action. The use of this spare transformer has negative implications for reliability and resiliency for both Valley South and Valley North Systems because it cannot be relied on for its intended function as a spare when used to serve load.

Project Objectives

The purpose of this Planning Study is to: establish the basis for a project in the Valley South System under applicable planning criteria and reliability standards; evaluate a broad range of alternatives to satisfy the electrical need; and recommend the best solution. SCE's project objectives (which were described in the project Proponent's Environmental Assessment) include:

- Serve current and long-term projected electrical demand requirements in the Electrical Needs Area.
- Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer substations from the current Valley South System.
- Transfer (or otherwise relieve[9]) a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through the 10-year planning horizon.
- Provide safe and reliable electrical service consistent with SCE's Subtransmission Planning Criteria and Guidelines.
- Increase electrical system reliability by constructing a project in a location suitable to serve the Electrical Needs Area (i.e., the area served by the existing Valley South System).
- Meet project need while minimizing environmental impacts.
- Meet project need in a cost-effective manner.

This Planning Study is intended to address the need and required timing for such a project, consider additional alternatives that can meet these project objectives, and help support a determination of

[6] The 2018 adjusted peak demand, which includes weather adjustments to reflect a 1-in-5 year heat storm, was 99.9% of the Valley South System ultimate system design capacity (1,120 MVA). 2019 adjusted peak loads were slightly lower than 2018. 2020 adjusted peak loads have not yet been finalized but are expected to be similar to, or higher than, both 2018 and 2019 values based on the unadjusted values during the September 2020 heat storm.

[7] See Section 3.0 System Configuration for additional information related to Valley South's lack of system tie-line.

[8] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item H.

[9] Clarified from original objectives so as not to preclude non-wires alternatives.

which of the alternatives (including the ASP) best satisfies the project needs from the overall perspective of system benefit, cost and risk.

The approach used in this study is as follows:

- Provide supporting evidence confirming system needs.
- Establish a project need date based on SCE's load forecast and validation of that need with two independent load forecasts.
- Develop a set of robust alternatives that meet or exceed the 10-year load forecast.
- Assess compliance with SCE's Subtransmission Planning Criteria and Guidelines.
- Assess each alternative using forward-looking quantitative metrics to assess the effectiveness of each alternative in meeting the project capacity, reliability, and resiliency[10] needs that currently exist in the area served by the Valley South System in its current configuration.
- Site and route the alternatives in order to evaluate feasibility and assess the relative environmental impacts of the alternatives.
- Estimate the costs of these alternatives and conduct a cost-benefit analysis that considers the benefits and costs over a 30-year life of the installed facilities.
- Identify risks which could impact the ability of the alternatives to meet project needs or alter their cost effectiveness.
- Recommend a preferred solution based on a comprehensive evaluation of alternatives.

Load Forecast

A 10-year load forecast (2019-2028)[11] prepared by SCE showed that the load on the Valley South System is expected to exceed the existing transformer capacity at Valley Substation by 2022[12] and that system load would continue to increase at a modest rate (<1% per year) over the next decade. The development of this forecast is consistent with CPUC direction that SCE use the California Energy Commission (CEC) annual California Energy Demand (CED) forecast produced as part of the annual Integrated Energy Policy Report (IEPR). Additionally, it is consistent with observed trends of historical loading data and historical population growth for the Valley South System service area. Two independent load forecasts for the Valley South System conducted by Quanta Technology[13], using distinct methodologies, confirm this need date and yield similar results: loading of the Valley South System is projected to exceed existing capacity in 2022 and modest positive growth rates would be expected to continue. The SCE forecast, as well as the independent

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[10] Reliability refers to a utility's ability to meet service requirements under normal (N-0) and N-1 contingency conditions. Resiliency refers to a utility's ability to keep its systems functioning and serving customers under extraordinary circumstances. These terms relate directly to the system tie-line project objective. See Appendix A for a complete discussion of these terms.

[11] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.

[12] Slightly lower 2019 adjusted peak load data slightly shift the need date to 2023. This modest shift does not impact the results of the analysis presented herein. The impact of higher actual peak loads experienced in 2020 have not yet been determined, but SCE considers it is more likely to maintain or advance the need date rather than delay it.

[13] Quanta Technology is an expertise-based, independent technical, consulting, and advisory services company specializing in the electric power and energy industries.

forecasts, incorporated accepted methods for consideration of Distributed Energy Resources (DERs) including energy efficiency, demand response, and behind-the-meter generation (See Section 5.0).

Development and Analysis of Alternatives

SCE and Quanta Technology developed a robust list of project alternatives based on a variety of inputs including: the direction of the CPUC in the ASP decision; the previous assessment of alternatives in the ASP EIR; and public and stakeholder engagement. Project alternatives include:

- Minimal Investment Alternatives (e.g., utilize existing equipment or make modest capital investments of <$25M);
- Conventional Alternatives (e.g., substation and wires-based solutions with system tie-lines);
- Non-Wires Alternatives (NWA) (e.g., battery energy storage systems (BESS), as well as the consideration of demand side management (DSM) and other DERs[14]); and
- A combination of Conventional Alternatives and Non-Wires Alternatives (herein referred to as Hybrid Alternatives).

These alternatives are described in Section 6.1 of this Planning Study.

SCE screened project alternatives against the project objectives. Those alternatives that met all of the project objectives were carried forward for evaluation using a combination of forward-looking quantitative reliability/resiliency metrics and other qualitative assessments. Although NWAs on their own do not meet all the project objectives (specifically the creation of system tie-lines), SCE carried forward a BESS-only alternative in the analysis in order to investigate the relative cost-benefit performance of a BESS solution alone and when paired with Conventional Alternatives to demonstrate the benefit of the system tie-lines. Importantly, establishing system tie-lines satisfies both the capacity and the reliability/resiliency needs facing the Valley South System by providing the ability to transfer electrical load during system contingency events.[15]

In order to assess and compare the project alternatives on a technical basis, the system was modelled and analyzed using the General Electric Positive Sequence Load Flow (PSLF) analysis software. PSLF is a software tool commonly used by power system engineers throughout the utility power systems industry, including many California utilities and the California Independent System

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[14] Ultimately in order to consistently address DER performance and cost across alternatives, battery energy storage systems were modelled as surrogates for all DER types, either on a centralized basis (subtransmission level) or on a distributed basis (distribution level, front of meter resources).

[15] Hybrid alternatives that adopt NWAs first, for capacity relief and to defer investment in Conventional Alternatives, were considered in project screening but not carried forward for further study. This is because system tie-line creation was deemed to be a priority at the onset of the project and system load transfers associated with system tie-line creation created sufficient capacity relief for more than 10 years. Accordingly, addition of NWAs at the project onset would be duplicative and inefficient from a cost perspective. Hybrid alternatives that were carried forward adopt NWAs later in time to address capacity needs beyond those initially satisfied by the system configuration changes associated with tie-line creation.

Operator (CAISO), to simulate electrical power transmission networks and evaluate system performance. To support this analysis, one of the two Quanta Technology load forecasts, the Spatial Load Forecast (SLF), was extended to 30 years, roughly corresponding to the economic life of conventional transmission and distribution assets that make-up the ASP and all of the alternatives that meet the project objectives. This extended SLF looks at small, discrete areas (150 acres in size) and considers geo-referenced individual customer meter data (peak load), local land-use information, and county and city master and specific development plans and thus is particularly well-suited among load forecasting methods for long term forecasts.

The reliability/resiliency metrics were quantified using the power system models of the Valley electrical systems in their current configurations and as they would be configured with the various alternatives. An 8,760 hour load shape[16] of both the Valley North and Valley South Systems was utilized and scaled according to the peak demand given by the SLF for each of the years under study. During each hour, the model determines how much, if any, load is required to be transferred to an adjacent system (if system tie-line capacity is available) or dropped (if system tie-line capacity is not available) to maintain the system within specified operating limits consistent with SCE subtransmission planning criteria. The dropped (or unserved) load is then summed over the 8,760 hours of the year, for base (N-0) and contingency (N-1, N-2)[17] conditions, to provide the basis for most of the metrics described below. The reliability/resiliency metrics used to evaluate the alternatives (discussed in greater detail in Section 6.3) include:

- Load at Risk (LAR) – total load required to be curtailed during periods of time in which subtransmission operating criteria were not met (thermal overload/voltage violation) multiplied by the number of hours of violation, quantified in megawatt-hours (MWh). This metric is calculated for operating conditions with all facilities in service (N-0 conditions) and with a single facility out of service (N-1 contingency conditions).
- Maximum Interrupted Power (IP) – maximum power, in MW, curtailed during thermal overload and voltage violation periods.

- Losses – total losses in the system, quantified in MWh, for each alternative (this is the only metric not driven by unserved load and is reflective of the electrical efficiency of each alternative).
- Flexibility 1 (Flex-1) – accumulation of LAR for all possible N-2 contingencies. N-2 contingencies are only considered for lines that share common structures. System tie-lines are utilized when needed and available. Thus, the Flex-1 metric provides a relative indication of the effectiveness of system tie-lines and the locational benefit of any new power source substations in improving system reliability and resiliency in the context of line outages.

[16] There are approximately 8,760 hours in a year. A common tool used for planning purposes is to construct a time-series data set of the system load on an hourly basis.

[17] N-0, N-1, and N-2 are electric system planning designations for operating contingencies, where N-0 refers to normal operation with all major system elements (e.g., transformers, lines, and busses) in service and N-1 and N-2 refer to scenarios with 1 or 2 elements out of service, respectively.

- Flexibility 2-1 (Flex-2-1) – amount of LAR in the Valley South System under a complete loss of transformation capacity in the Valley Substation) due to a high impact, low probability (HILP) event. This event is postulated to be similar to substation fires that have occurred previously in the SCE system[18] but could also result from external causes such as an earthquake, wildfire, sabotage, or electromagnetic pulse (EMP) event. The resulting outage is assumed to occur randomly throughout the year and to have a duration of two weeks – the estimated minimum time to deliver, install, and in-service the remotely located spare 500/115 kV transformer and to also repair associated bus work, structures and/or and transformer auxiliary equipment that could have been damaged. During an extreme HILP event, a 2-week outage assumption likely understates the recovery time, but the minimum time is assumed to limit the impact of this single metric on the overall analysis. A catastrophic failure of this type could take a period of several months to recover from and return to the pre-event state. The installed Valley Substation spare and offsite spare transformers are then assumed to be in service to serve the Valley South System load. System tie-lines (when available) are used to transfer load to adjacent systems during the interim period before service is restored to the Valley South System in order to minimize the customer impact of the outage.
- Flexibility 2-2 (Flex-2-2) – amount of LAR under a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other. The bus work is assumed to remain operable, as are the Valley North transformers, so the spare transformer is assumed to be available to serve load in the Valley South System. System tie-lines would be utilized to reduce LAR. Like Flex-2-1, the coincident transformer outages are assumed to occur randomly throughout the year and to have a duration of two weeks – the estimated minimum time to deliver, install, and in-service the remotely stored spare Valley transformer to restore full transformation capacity to Valley South. System tie-lines are used (when available) to transfer load to adjacent systems during the period before full Valley South system transformation capacity is restored in order to minimize the customer impact of the outage. The difference between Flex 2-2 and Flex-2-1 metrics is that, under a Flex 2-2 scenario, one transformer continues to be available to serve Valley South load whereas in the Flex-2-1 scenario, no transformers are available.

As described in more detail in Section 6.4 and summarized in Table ES-1, the metrics demonstrate the effectiveness of each of the alternatives in addressing the capacity, reliability, and resiliency needs in the areas served by the Valley South System in its current configuration over both short term and long-term horizons.

[18] Three SCE AA substations (Vincent, Mira Loma, and El Dorado) have experienced similar events in the past 20 years.

Table ES-1 –Performance Improvements through 2028 and 2048 for All Alternatives

Alternative	Results Through 2028		Results Through 2048	
	Capacity Improvement	Reliability/ Resiliency Improvement	Capacity Improvement	Reliability/ Resiliency Improvement
No Project	0%	0%	0%	0%
Alberhill System Project	100%	~~98~~99%	99%	97%
SDG&E	100%	87%	99%	82%
SCE Orange County	99%	~~85~~86%	93%	~~79~~80%
Menifee	100%	~~67~~79%	92%	~~62~~74%
Mira Loma	100%	36%	77%	34%
Valley South to Valley North	100%	3%	78%	6%
Valley South to Valley North to Vista	100%	3%	89%	6%
Centralized BESS in Valley South	100%	1%	100%	~~3~~4%
Valley South to Valley North and Distributed BESS in Valley South	100%	3%	81%	7%
SDG&E and Centralized BESS in Valley South	100%	87%	100%	83%
Mira Loma and Centralized BESS in Valley South	100%	36%	100%	35%
Valley South to Valley North and Centralized BESS in Valley South and Valley North	100%	3%	95%	6%
Valley South to Valley North to Vista and Centralized BESS in Valley South	100%	3%	92%	6%
Note: Performance improvements for each alternative represent the percentage of LAR reductions over the No Project Scenario. LAR N-0 and LAR N-1 are capacity metrics, while Flex-1, Flex 2-1, and Flex-2-2 are reliability/resiliency metrics.				

Because all of the system alternatives were designed to meet the system capacity needs over at least the initial ten-year project planning horizon, very little difference was shown among the alternatives from the perspective of capacity-related metrics LAR (N-0) and LAR (N-1) through 2028 (as evidenced by all alternatives showing at least an 99% capacity improvement in this period).[19] However, the reliability/resiliency driven Flex-1 and Flex-2 metrics clearly differentiated among the project alternatives, particularly in revealing the relative effectiveness of the system tie-lines (as evidenced by the broad range of reliability/resiliency improvements through 2028 and 2048).

[19] The alternatives that merely transfer load from one system to another without introducing a new substation sourcing power from the bulk electric system are not as strong on capacity related metrics beyond 2028 and would need to be augmented with DERs or some other project solution to meet system planning criteria much beyond this initial ten-year planning horizon.

Alternatives that would construct new substations, and therefore new transformation capacity (such as the ASP, SDG&E, and SCE Orange County) performed well with respect to both the capacity and reliability/resiliency metrics, since they transfer a large quantity of load from the Valley South System, and have the ability to take on additional load (through the use of the system tie-lines) during planned or unplanned outages. Generally, projects that included construction of new transmission substations showed the greatest overall improvement in reliability/resiliency metrics among the alternatives.

Alternatives that would transfer load from the Valley South System to an adjacent system, such as the Valley South to Valley North and Valley South to Valley North to Vista alternatives, were shown to perform moderately well in capacity improvement. However, they did not perform well in the reliability/resiliency category due to the lack of robust system tie-lines and the resulting lack of ability to accommodate additional load transfers to adjacent systems from Valley South during planned or unplanned outages.

Mira Loma performs well through 2028 from a capacity perspective, since the initial transfer of substations provides enough transformer capacity margin to the Valley South System for the 10-year planning horizon (2028). However, the system-tie lines created by this alternative are limited in their ability to transfer supportive load out of the Valley South System for the potential double-circuit N-2 contingencies (i.e., the transferred load does not significantly alleviate the overloaded lines during the N-2 contingencies). Additionally, under a catastrophic event at the Valley Substation (Flex-2-1) the total amount of load that can be transferred out of the Valley South System to the new Mira Loma system is less than that of other substation-based alternatives. The poor long-term performance of the Mira Loma alternative is due to the limited N-0 capacity margin provided to the Valley South System, because the Valley South System transformers would again become overloaded in 2031. This is the earliest date among all of the alternatives that the Valley South System transformers are projected to again be overloaded.

The Menifee alternative, despite including a new source substation, does not perform as well as the ASP, SCE Orange County, or SDG&E substation alternatives with respect to the reliability/resiliency metrics. This is because the location of the Menifee alternative substation, effectively adjacent to Valley Substation, does not allow for the creation of system tie-lines that are effective in reducing the impact of the line and transformer outages considered in the Flex-1 and Flex-2 metrics. This limitation and its cause are addressed further below and in Section 8.2.1 in discussing the cost-benefit analysis performance of this alternative. Additionally, Menifee is a less effective system solution than these other alternatives due to the proximity of the Menifee substation to the Valley Substation and resulting vulnerability to external events affecting both stations. This limitation is not reflected in the metrics because the impact of the assumed Flex-2 scenarios is confined to the boundaries of the Valley Substation.

Compliance with SCE Planning Criteria

Table ES-2 illustrates how alternatives compare in meeting requirements of SCE's Subtransmission Planning Criteria and Guidelines. This table indicates the alternatives which result in transformer overloads (and identifies the year of the overload), and the number of N-0 and N-1 line overloads through 2048; any of these overloads represent a violation of SCE's planning criteria. The alternatives which do not result in transformer overloads, and have limited

N-0 and N-1 line violations, are more robust, and are more capable of meeting the planning criteria over a longer time frame than those with transformer overloads and line violations. The ASP and the majority of the hybrid alternatives are the only alternatives which do not result in transformer overloads through 2048 (the BESSs associated with the hybrid alternatives were sized to mitigate transformer overloads). While project scope was included to address line violations for N-0 and N-1 conditions through 2028 for all alternatives, by 2048 the number of N-1 violations significantly increases for some alternatives, such as SCE Orange County, Menifee, all of the alternatives that include a Valley South to Valley North load transfer, and Mira Loma. While these violations can be remedied through future projects (typically reconductor or complete rebuild of the lines), the sheer number of line violations for these alternatives demonstrates the relative ineffectiveness of several of these alternatives during N-1 conditions over the long-term.

Additionally, the system analysis demonstrates that several of the alternatives (Centralized BESS in Valley South, Menifee and all of the Valley South to Valley North alternatives), do not satisfy the project objective of achieving VS system compliance with the subtransmission planning criteria associated with having system tie-line capacity to transfer load to adjacent systems when needed to mitigate the potential loss of service to customers in Valley South (see Table 4-1).

Table ES-2 – Planning Criteria Violations for All Alternatives

Alternative	Year of Transformer Overload	Number of N-0 Line Violations Through 2048	Number of N-1 Line Violations Through 2048
Centralized BESS in Valley South	N/A	0	0
SDG&E and Centralized BESS in Valley South	N/A	0	0
Mira Loma and Centralized BESS in Valley South	N/A	0	1
Valley South to Valley North and Centralized BESS in Valley South and Valley North	N/A	0	5
Alberhill System Project	N/A	1 (in 2046)	3
Menifee	VS: 2043	0	6
Valley South to Valley North to Vista and Centralized BESS in Valley South	VN: 2041	0	5
Valley South to Valley North to Vista	VN: 2041	0	0
	VS: 2043	0	6
SDG&E	VS: 2040	0	0
SCE Orange County	VS: 2040	0	4
Valley South to Valley North	VN: 2037	0	0
	VS: 2043	0	6
Valley South to Valley North and Distributed BESS in Valley South	VN: 2037	0	5
Mira Loma	VS: 2031	0	10

Note: This table is organized to illustrate how effective each alternative is in meeting SCE Subtransmission Planning Criteria and Guidelines over the long-term (through 2048). Alternatives are ordered according to their ability to provide adequate transformation capacity, which could be considered the most critical criterion to meet, given that adequate transformer capacity is essential in meeting customer load demands, and a lack of this capacity is typically the most costly to remedy. The alternatives are then ranked by N-0 line violations, which can be considered the next most critical criterion, since these overloads occur under normal operating conditions, as opposed to N-1 violations, which occur only under abnormal operating conditions.

Note: Voltage violations are not included in this table. The amount of load- at- risk from these violations is small compared to the load- at- risk due to line overload violations.

Siting and Routing

Siting and routing studies were performed for each of the alternatives, consistent with SCE's project siting and routing process. The siting and routing studies identified preferred substation sites and line routes, which were used to assess risk (e.g., agency permitting delays; uncertainty in the extent of licensing and public opposition; scope within wildfire areas; etc.), understand potential environmental impacts, and estimate associated costs for each of the project alternatives. While all alternatives reviewed are expected to be feasible based on the level of analysis performed, SCE determined that there are substantial differences in the complexity and risk associated with individual alternatives. These factors are reflected, to the extent possible, in the cost estimates for alternatives and are discussed qualitatively as part of this Planning Study. It is important to note that some of the alternatives are expected to have substantial challenges in licensing and permitting due to the specific nature of the routes and prior experience with affected communities, and because they have not yet been subject to California Environmental Quality Act (CEQA) review. SCE intentionally limited the extent to which it monetized the risk of delays and higher costs associated with siting, routing and licensing risk to ensure that the system performance merits of individual alternatives would not be discounted by subjective judgements of cost and schedule. For example, in the cost/benefit models presented here, all projects are assumed to be in service in 2022, at the time of the project need, while, in reality, there would likely be considerable differences among alternatives in terms of in-service date. See Section 7.0 Siting and Routing and Section 9.0 Risk Assessment, for additional information.

Cost Estimates

Project cost estimates were developed for each alternative at a level of confidence commensurate with a feasibility study level of design and analysis (e.g., Association for the Advancement of Cost Engineering (AACE) Level 3/4). Environmental monitoring and mitigation costs that are driven by specific siting and routing factors were included for each project alternative. The estimates included provisions for contingency and risk consistent with the level of development and design conducted to date and SCE's standard risk assessment and quantification process. For projects incorporating BESS, market participation revenues were applied to offset costs.

ASP costs are based on SCE's Direct Testimony Supporting its Application for a Certificate of Public Convenience and Necessity to Construct the ASP, dated July 17, 2017 (SCE Amended Cost Testimony)[20], and were adjusted to account for ongoing licensing costs, and the escalation from 2017 dollars to 2019 dollars. As the ASP is the only solution that has undergone significant design, environmental analysis, and project engineering to date, the remaining alternatives suffer from higher cost uncertainty due to the lack of environmental analysis, licensing, and engineering design efforts. Importantly, uncertainty costs were capped at 50% in accordance with expected accuracy of Level 3/4 AACE cost estimates, to limit the impact of uncertainty on study results. However, SCE's experience is that project costs for projects that have not been through the complete process of development, design, licensing, and stakeholder engagement can change by more than 50% when advancing to the execution stage. The risks of higher costs are therefore addressed on a qualitative basis elsewhere in the Planning Study. See Section 8.1.1 Costs and Section 9.0 Risk Assessment for additional information.

[20] See Table IV-1, page 25 of Section IV, "Southern California Edison Company's Direct Testimony Regarding the Maximum Prudent and Reasonable Cost of the Alberhill Project and the Qualifications of SCE Witness Gordon Tomaske".

In general, the projects that transfer load from one system to another via new subtransmission lines tend to be lowest in total cost, while those that incorporate new substations tend to be highest. Incremental battery additions to meet capacity needs are relatively inexpensive in early years; however, as the duration of overloads increases with time, the costs become substantial since large battery additions are required to meet energy needs. This is reflected in the BESS-only solution being the highest cost alternative in aggregate nominal dollars.

Monetization of System Performance Metrics

For the purpose of performing a cost-benefit analysis, the system performance metrics described above were monetized using 1) historical SCE line and transformer outage frequency data to probabilistically weight the loss of service metrics, and 2) the cost of service interruption data from SCE's Value of Service study (as presented in the SCE General Rate Case[21]). The primary objective of the Value of Service study is to estimate outage costs for various customer classes, using the well-established theoretical concept of "value-based reliability planning." This concept has been used in the utility industry for the past 30 years to measure the economic value of service reliability. The estimation of outage costs differs by customer classes: commercial and industrial outage costs are based on a direct-cost measurement, since these costs are easily measured, whereas residential outage costs are based on a willingness-to-pay survey.

Four capacity, reliability, and resiliency performance metrics were monetized to develop the benefits of each alternative: LAR under N-0 conditions; LAR under N-1 conditions; Flex-1; and Flex-2.[22] These metrics most accurately reflect the capacity, reliability, and resiliency benefit of the alternatives to SCE customers, most readily differentiate the alternatives, and can be probability weighted, monetized, and combined to reflect the overall benefit of alternatives[23]. When monetized, the LAR metrics are designated as Expected Energy Not Served (EENS) to reflect the assignment of probability weighting of the event scenarios and thus reflecting the actual expected unserved energy need for customers. Both costs and benefits are discounted to present day using financial parameters consistent with SCE's Present Value Revenue Requirement (PVRR)[24] model that reflects the overall present-day discounted effect of long-term investments on customer rates.

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[21] See WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A – pp. 12 – 109 – Southern California Edison: 2019 Value of Service Study.

[22] Additionally, improvements (i.e., reductions) in system losses were monetized based on projected future locational marginal pricing projections; however, the monetized values were low compared to the some of the other monetized system performance metrics and did not significantly distinguish among alternatives.

[23] Additionally, system losses are monetized. However, while different among the alternatives, the monetized values of the differences among the alternatives are small relative to the overall monetized benefits.

[24] PVRR is the ratepayer revenue required to repay an investment over its life converted into a common basis in current-year dollars. It is similar to a net present value. See Exhibit No SCE-01, Application A.13-10-XXX, West of Devers Upgrade Project, "Testimony Supporting Southern California Edison's Request for an Interim Decision Approving the Proposed Transaction", submitted October 25, 2013 before the Public Utilities Commission of the State of California.

The results of the analysis show that the majority of monetized benefit is associated with the EENS (N-0) and Flex-2 benefits. These benefits are associated with capacity and resiliency respectively. The value of the EENS (N-1) and Flex-1 benefits is low due to the localized impact of outages contributing to EENS (N-1) benefits and the relatively low probability of coincident outages and high loading conditions that contribute to substantial loss of service to customers. However, as discussed further below, should such an event occur, the cost and impact to customers would be severe for alternatives that do not provide adequate system tie-line capacity.

The monetized system benefits show that all evaluated alternatives demonstrate SCE customer benefits that well exceed the respective project cost.[25] The large magnitude of benefits compared to project costs is not unexpected, given the number of customers served by the Valley South System who would be impacted by electric service outages and the value customers place on their electric service.

As was the case for the system performance metrics (before monetization) described above, the alternatives that directly address the capacity need through the construction of adequate substation transformation capacity, such as the ASP, SDG&E, and SCE Orange County, and directly address the reliability/resiliency by diversifying the source power location and allowing the transfer of load out of Valley South through the use of system tie-lines provide the greatest overall benefits. These alternatives provide a means to initially transfer a large amount of load away from the Valley South System, thus increasing the operating margin of the Valley South System transformers and extending the timeline for when the transformers would again be at risk of becoming overloaded. In addition, the effectiveness of the system tie-lines created in these alternatives is maximized, since the new substations (with substantial transformation capacity) do not constrain the amount of additional load that can be transferred during planned or unplanned contingencies.

Similar to SDG&E, SCE Orange County and ASP, the Menifee alternative also creates a new source substation and thus also addresses much of the capacity and reliability/resiliency need. However, as discussed above, the Menifee alternative does not meet project objectives because its system tie-lines are ineffective in that they do not allow transfer of capacity out of Valley South beyond that which was initially transferred in implementing the initial project. Additionally, the location of the Menifee alternative substation would not be as effective in addressing the diversification of the locations of the source power to the region as that of ASP. The resiliency need represented in the metric is constrained to external and internal events that affect the equipment within the Valley Substation fence line. To the extent that a HILP event's impact could extend beyond the substation boundary (such as a large-scale wildfire, high wind event, or earthquake), the effectiveness of Menifee alternative in addressing the resiliency need would be substantially diminished relative to the performance that is represented by the metric.

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[25] The cost to benefit analysis described herein differs from a traditional cost to benefit analysis in which the benefits realized represent offset or reduced future costs (i.e., provide a return on investment). For the purposes of this analysis, the costs reflect estimated project costs, whereas the benefits are to SCE's customer base and are associated with the avoidance of loss of electric service. This is an appropriate approach when analyzing utility-sponsored capital projects, where the utility has an obligation to provide safe and reliable electric service to customers and is therefore incentivized to maximize customer benefits, while also earning a fair return on investment through general rate increases.

Hybrid alternatives that use BESS to address long-term capacity shortfalls, along with system tie-lines, would provide the next highest level of overall benefits, whereas alternatives that transfer load from one existing system to another, such as the Valley South to Valley North and Valley South to Valley North to Vista alternatives, provide the least overall benefit. While these load-transfer alternatives perform reasonably well in improving short-term capacity (99% capacity improvement through 2028), they do not significantly improve reliability/resiliency during contingency events.

The very limited effectiveness of tie-lines for the Menifee and all of the Valley South to Valley North alternatives is because these alternatives essentially construct new subtransmission lines to transfer load away from the Valley South System on a permanent basis and the resulting system tie-lines only provide the opportunity to transfer this load back to the Valley South System in contrast to system tie-lines that would allow for bi-directional transfers. This is directly attributed to location of these alternatives (e.g., adjacent to or within Valley Substation). In order to create effective system tie-lines for these alternatives, additional distribution substations would need to be transferred out of Valley South. However, the distribution substations which are most accessible to transfer in these alternatives are substations through which power coming from the Valley South System transformers is routed before continuing on a path to serve the remaining distribution substations to the southern part of the system. Transferring these nearby substations, without significant additional 115 kV subtransmission line construction to effectively bypass them, would disrupt the design of the electrical network and adversely impact the ability to serve the more distant substations in the Valley South System. The amount of additional load that can be transferred during planned or unplanned contingencies is therefore limited. This is why it is much easier (and cost-effective) to create effective system tie-lines by transferring distribution substations at the periphery of the radial subtransmission system than by transferring distribution substations located near the source subtransmission substation. See Section 8.1.2 (Benefits) for additional information.

Benefit-to-Cost Results

As discussed in more detail in Section 8.2 of this Planning Study, the results of the cost/benefit analysis are presented in two ways: benefit-to-cost ratio and incremental cost-benefit analysis. The benefit-to-cost ratio is obtained by simply dividing the present value of monetized benefits by the PVRR, which represents total cost. The ranking of alternatives on this basis is shown in Table ES-3 below.

Table ES-3 – Benefit/Cost Analysis Results for All Alternatives

Alternative	PVRR ($M)	Benefits ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$4,282	9.0	Yes
SDG&E	$453	$4,001	8.9	Yes
Mira Loma	$309	$2,601	8.4	Yes
SDG&E and Centralized BESS in Valley South	$531	$4,041	7.6	Yes
Mira Loma and Centralized BESS in Valley South	$560	$3,132	5.6	Yes
SCE Orange County	$748	$4,021	5.4	Yes
Menifee	$331	$~~3,648~~3,882	11.~~0~~7	No
Valley South to Valley North	$207	$2,156	10.4	No
Valley South to Valley North and Distributed BESS in Valley South	$232	$2,165	9.3	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	$2,~~468~~479	8.~~5~~6	No
Valley South to Valley North to Vista	$290	$2,470	8.5	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	$2,542	6.9	No
Centralized BESS in Valley South	$525	$2,535	4.8	No

The project alternatives with highest benefit-to-cost ratios primarily achieve their rankings due to lower costs. These lower costs are driven in most cases by system solution limitations that do not enable the projects to fully satisfy project objectives. These limitations are also reflected in lower benefits. For example, as previously discussed, the Menifee and various Valley South to Valley North alternatives do not have effective system tie-lines. In another case (Mira Loma), the alternative meets project objectives but is a shorter term capacity solution and has system tie-lines that are not as effective as other source substation alternatives. When costs of longer-term capacity additions are considered, Mira Loma has a correspondingly lower benefit-to-cost ratio (the Mira Loma and Centralized BESS in Valley South alternative has a lower benefit to cost ratio than Mira Loma alone).

In performing a cost-benefit analysis of alternatives with widely disparate benefits, it is appropriate to perform an incremental cost-benefit analysis in which the incremental cost for higher-cost alternatives is weighed against the incremental benefits. This approach formalizes and quantifies the process used in the decisions made by consumers when they decide whether buying a higher priced product is "worth it." On this incremental cost-benefit basis, the ASP is superior to all other alternatives, because it provides the most increase of benefits per unit of incremental cost. The

~~SDG&E~~Menifee alternative was the second ranked alternative in this case. The ratio of the incremental benefits to incremental costs for ASP versus ~~SDG&E~~Menifee is ~~13.4~~2.8, which demonstrates the cost effectiveness of increased spending to achieve greater benefits.

Sensitivity Analysis

SCE recognizes there is additional potential option value in alternatives with less expensive upfront costs that meet system needs for a shorter time frame over alternatives with higher upfront costs but longer- term system benefits. Specifically, should load develop slower than forecasted, the alternatives with lower front -end costs would incur future costs later than currently modeled, thus favorably affecting their cost-benefit performance. An analysis was performed to evaluate the sensitivity of the cost-benefit analysis results to uncertainty in the 30-year load forecast (see Section 5.4). SCE considered forecasts that were reflective of growth rates that were lower (0.6%/year) and higher (1.0%/year) compared to the base forecast growth rate (0.8%/year), by considering varying rates in DER growth and electrification. In each case, future incremental costs for the Hybrid alternatives incorporating BESS were adjusted to meet the forecasted load growth rate. For the lower forecast, the overall benefit -to -cost ratios were reduced. However, the relative results were not substantially changed other than a reduction in the performance of the Valley South to Valley North alternatives due to a reduction in their capacity benefits. For the higher load forecast, the overall benefits increased by a large amount but the relative results among the alternatives again do not change substantially. The Valley South to Valley North alternatives that rely on BESS additions are adversely affected due to the high costs of BESS additions to meet the greater capacity need. The ASP performs best in incremental benefit-to-cost ratio among alternatives in both lower and higher load forecast sensitivity case scenarios.

Lower upfront cost alternatives that incrementally add BESS to meet capacity needs could also benefit from lower than expected future costs through improvements in technology or market conditions. An additional sensitivity case was performed that reduced the costs of the BESS by 50% from the nominal costs assumed in the benefit-to-cost analysis. As expected, the benefit-to-cost ratios of the hybrid alternatives improved relative to conventional alternatives under this scenario; but even when the lower cost BESS and low load growth scenarios are combined, the substation-based alternatives perform best in overall benefit-to-cost ratio and the ASP continued have superior incremental benefit-to-cost performance.

Overall, this sensitivity analysis demonstrates that for reasonable downward adjustments in forecast load and BESS costs, the option value of deferring capital investments needed to meet system requirements is not likely to be substantial in light of the near-term need for system tie-lines to address the system reliability/resiliency needs. Further, the analysis demonstrates that the ASP and other conventional substation alternatives are robust from the perspective of addressing future load growth uncertainties, providing margin for higher future load growth from enhanced electrification scenarios beyond those considered in this analysis (see Section 9.4).

Risk Assessment

A risk assessment was performed to address other risks that were not monetized explicitly in the cost/benefit analysis (see Section 9.0). Among these risks, the most consequential is the uncertainty of licensing timelines and achievability for several of the alternatives. As discussed above, for simplicity, the accrual of project benefits for all alternatives were assumed to be concurrent with the 2022 project need date. While the ASP has been substantially vetted through regulatory and public scrutiny, the other alternatives have not, meaning the implementation costs for the other 12 alternatives could be even greater than those costs considered within the risk and uncertainty limits in the cost-benefit analysis. The licensing period associated with further development of alternatives, followed by CEQA review, would have the effect of reducing the benefits (due to the ongoing unavailability of system tie-lines) and increasing both the reliance on the current mitigation that is used to address the capacity shortfall and the risk to customers of loss of service due to a HILP event at Valley substation. For each year of delay, the reduction in overall benefits to customers would increase from a range of $4.3M to $148M.[26] If these likely licensing delays and associated cost and benefit impacts were to be monetized in the cost-benefit analysis, the alternatives with expected longer licensing durations would perform much less favorably than the ASP.

The consequence of project delays in risk of loss of service customers is masked to some extent in the assignment of probabilities to individual event scenarios. When one considers the real possibility of N-2 line and substation events occurring and that the probability of such an event is enhanced at periods of time when the systems are most vulnerable (high temperatures and high loading conditions), the consequences of these events are more apparent. For example, in considering the real possibility of a Flex-2-1 type event[27] occurring in 2028 on or near a peak load day without an appropriate project in place (i.e. one with adequate capacity and effective tie-lines and diverse location) the impact would be:

- Over 200,000 metered customers (>500,000 people) would lose service with no practical way to restore load in a timely manner

- The region would experience large scale economic impacts as well as disruption of public services

- Customers would experience a financial impact of several billion dollars (based on VoS study outage costs as well as published costs of recent widespread outages[28]).

Similarly, while the impact on N-2 line outages would be somewhat more localized, the consequences are also large. As an example, with no project in place, if a single 4-hour N-2 outage were to occur for the Valley-Auld #1 and Valley-Auld #2 115 kV lines (which have a number of common poles) on a peak day in 2028 approximately 35,000 customers would lose service for this period. Based on the VoS Study, the cost to customers of this single event would be on the order of $55M. Other credible line outage combinations would have a similar impact. In both the case of substation and line N-2 events this impact occurs, because without a project to

[26] In 2022, the Centralized BESS in Valley South alternative provides $4.3M and the ASP provides $148M of benefits to customers. These benefits increase in subsequent years.
[27] Total loss of the power delivery to the Valley South System for a 2-week (minimum) outage to (remove, transport, and replace transformers, repair bus work, replace power and control cables, etc.)
[28] https://www.cnbc.com/2019/10/10/pge-power-outage-could-cost-the-california-economy-more-than-2-billion.html

add capacity and serve load in an alternative manner (e.g., through transfers using system tie-lines), load shedding would be required to mitigate overload conditions.

Recommendation

Based on the assessment described in this Planning Study, the recommended solution to solve the critical capacity, reliability, and resiliency needs of the Valley South System is the ASP. This recommendation is discussed in Section 10.0 of this Planning Study and is driven by the following factors[29]:

- Comprehensive Solution to Meeting Project Objectives: The Valley South System requires a comprehensive solution to address its distinct system needs. The system that has evolved from a series of short-term solutions is no longer adequate to serve SCE customers in this region and is critically deficient from the perspective of capacity, reliability, and resiliency. ASP provides a comprehensive, long term solution that most effectively meets all of the objectives defined at the onset of the project proceedings for the Valley South System.
- System Performance Improvement: ASP ranks highest among all of the alternatives in achieving over ~~96~~97% improvement in the system capacity, reliability and resiliency performance in serving the needs of the region through 2048, while other alternatives achieve at most 83% of the available benefits. Similar differences are seen in performance over an initial ten -year period through 2028.

- Cost Effectiveness: In the cost-benefit analysis of several alternatives, ASP was found to have a benefit-to-cost ratio that was much greater than 1 and near the top of the range of alternatives. ASP was found to be superior to all other alternatives from the perspective of incremental benefit-to-cost ratio, which weighs the cost effectiveness of the higher benefits of ASP relative to other alternatives. Those projects ranked near or higher than ASP on an absolute benefit-to-cost basis do not meet project objectives, are very short-term solutions, and/or have substantial risks associated with licensing and implementation.
- Optionality and Risk: The ASP solution is more robust than the other alternatives from the perspective of potential variations in future load growth and other risks and uncertainties, and its cost effectiveness relative to other alternatives is not significantly affected in future planning scenarios with lower load or lower cost NWAs. ASP has lower risk of cost increases than alternatives that have not been subject to years of design, analysis, and stakeholder engagement as has been the case for ASP.
- Timeliness of Project Implementation: All project alternatives, other than ASP, would require extended periods for design, CEQA analysis, and public engagement in new communities, which will effectively preclude having a solution in place until late in the 10-year planning period. When the prospects for project timing are realistically considered, ASP further separates favorably from other alternatives under consideration.

[29] DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item I provides a more extensive basis for the ASP recommendation.

2.0 Problem Statement

SCE's Valley South System currently serves over 187,000 metered customers, representing approximately 560,000 individuals, nearly 6,000 of which are critical care customers. The 2018 adjusted peak demand, which includes weather adjustments to reflect a 1-in-5 year heat storm, is currently at 99.9% of the Valley South System's ultimate system design capacity (1,120 MVA). Forecasted load growth shows that peak demand is expected to exceed the rated transformer capacity of the system by the year 2022.[30]

The Valley South System has a unique combination of characteristics as compared to SCE's other subtransmission systems that result in reliability and resiliency challenges and contribute to the likelihood of occurrence and/or impact of events that lead to loss of service to customers.[31] The reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity margin, configuration, and size. In its current configuration, the Valley South System is the only SCE subtransmission system that does not have any system tie-lines to other systems. This results in an isolated system with negative impacts to reliability and resiliency due to the inability to transfer load during typically planned-for system contingency events and unplanned outages, including high-impact, low-probability events. The lack of capacity and absence of system tie-lines requires a solution to maintain the integrity of the electric system, and to prevent and mitigate customer service outages.

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[30] See Section 4.0 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.
[31] See Section 4.0 of DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B.

3.0 System Configuration

3.1. Existing Valley System

The San Jacinto Region of SCE's service territory covers approximately 1,200 square miles. It includes the cities of Lake Elsinore, Canyon Lake, Perris, Menifee, Murrieta, Murrieta Hot Springs, Temecula, Wildomar, and areas of unincorporated Riverside County. SCE serves the area from its Valley Substation located in Menifee, CA which has two distinct electrical systems, the Valley North and Valley South Systems. The San Jacinto Region is at the southern-most point of SCE's 50,000 square mile service territory. It is bounded to the west by the Santa Ana Mountains separating it from Orange County, to the east by the San Jacinto Mountains separating it from the Palm Springs area, and to the south by the San Diego Gas & Electric service territory. The region and its surrounding geography are shown in Figure 3-1.

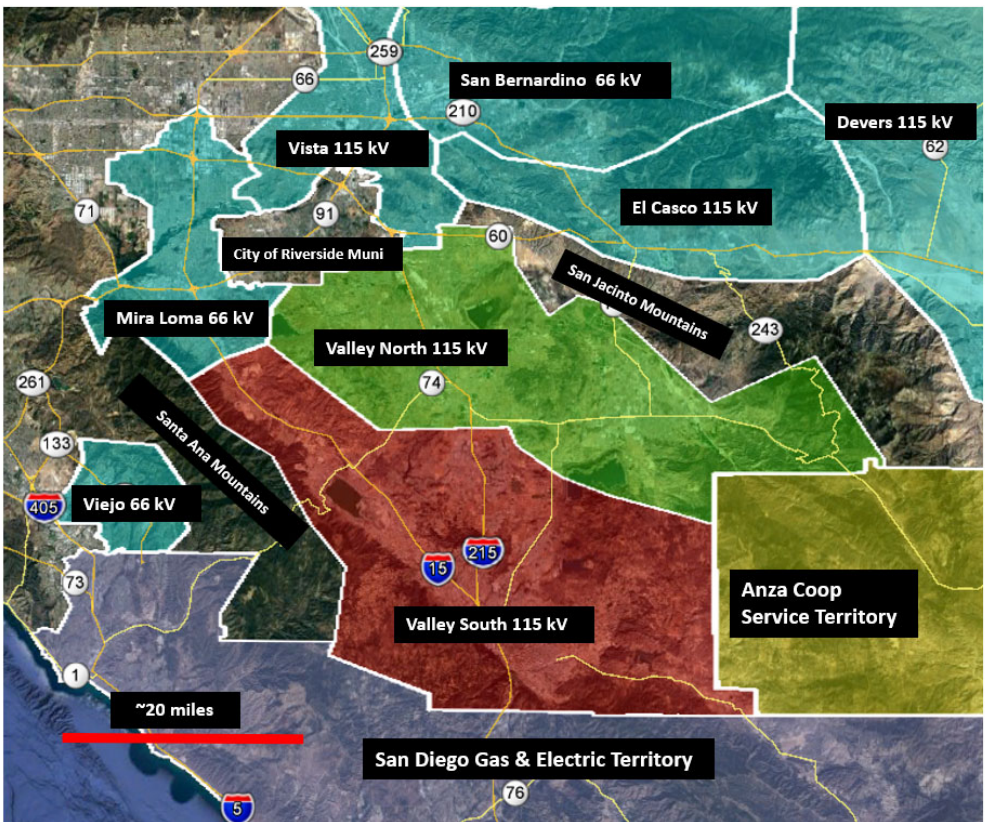

Figure 3-1 – San Jacinto Region Surrounding Geography and Electrical Systems

The region serves approximately 325,000 metered customers (Valley North and Valley South Systems combined) and provides electricity to approximately 1,000,000 people.[32] The customer

[32] The entire SCE entire service territory serves electricity to approximately 5,000,000 metered customers representing approximately 15,000,000 residents or on average three persons per meter. https://newsroom.edison.com/internal_redirect/cms.ipressroom.com.s3.amazonaws.com/166/files/20190/About%20 SCE.pdf

base is largely composed of residential customers. The area served by Valley Substation is also home to many large businesses, including Abbott Vascular, Amazon Fulfillment, Pechanga Resort & Casino, Infineon Technologies, Skechers Shoes, Ross Distribution, and several city electric utility municipalities such as the Anza Electric Cooperative and the City of Moreno Valley. Valley Substation is SCE's largest load-serving substation in total transformer capacity installed, total load served, and total population served.

The source of power to the area passes through a single point of delivery at Valley Substation which is connected to the CAISO-controlled Bulk Electric System at the 500 kV voltage level. Valley Substation delivers power to its distribution substations through four 560 MVA 500/115 kV transformers, two serving the northern area (Valley North System) and two serving the southern area (Valley South System). Figure 3-2 shows the existing Valley North and Valley South System configuration.

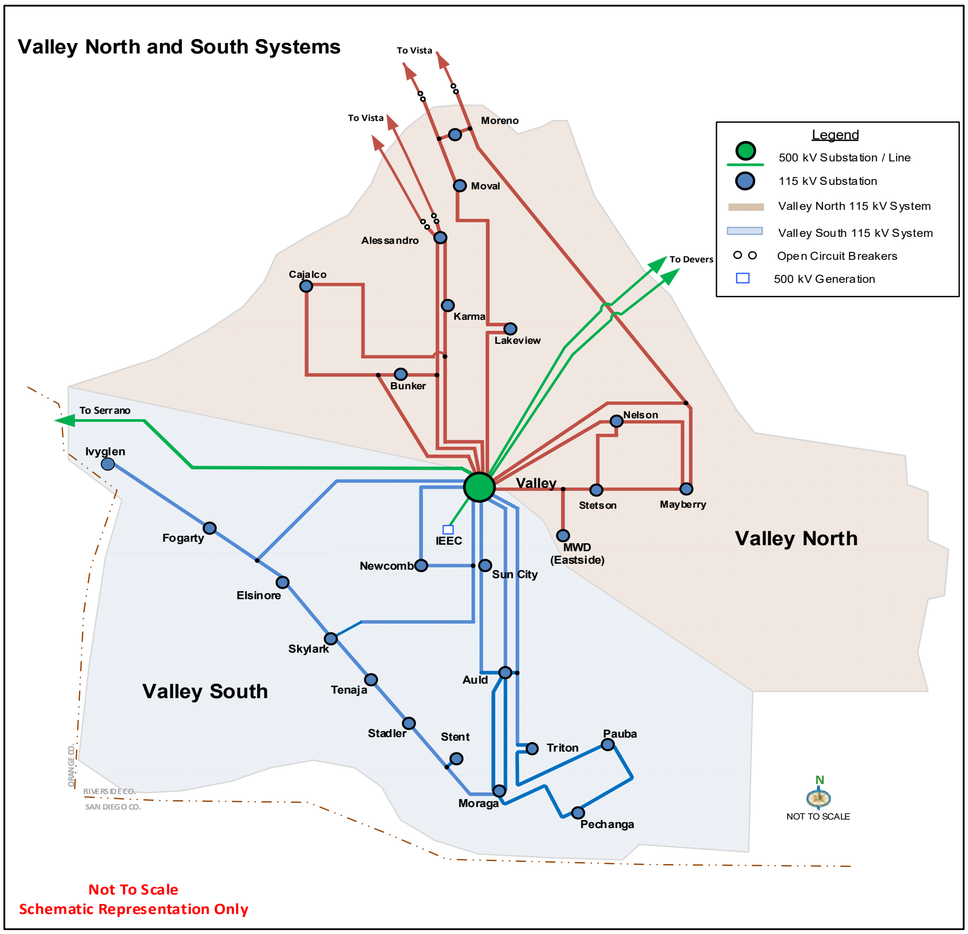

Figure 3-2 – Existing Valley North and Valley South Systems[33]

[33] Figure does not reflect configuration changes associated with the Valley South project (recently placed in-service as of issuance of Revision 2 of this study) and the Valley Ivyglen project (under-construction as of issuance of Revision 2 of this study). These projects are reflected in the analysis described in this study.

3.2. *Substation Transformation Capacity and "Split" Systems*

SCE's current electrical system has a total of 43 load-serving "A-bank" transmission substations that transform voltage from the transmission level (220 kV or 500 kV) to the subtransmission level (66 kV or 115 kV) and then deliver power to multiple distribution substations. Of the 43 A-bank substations, 42 of them are served by 220 kV transmission source lines. These 42 substations are designed in a consistent manner which provides benefits for planning, operations, and maintenance and each is designed to serve up to 1,120 MVA of capacity through the use of four 280 MVA transformers.[34]

Valley Substation is SCE's only A-bank substation that uses 500/115 kV transformers and is the only system which has transformers rated at 560 MVA - twice the capacity of the typical transformers used at all of SCE's other A-bank substations. Significant procurement time, cost, and logistical challenges are required in order to transport and install these 500/115 kV transformers. Hence, long lead times are required to replace a failed unit (which is why an on-site, installed spare transformer is required).

The initial build-out of an SCE A-bank substation typically includes two transformers. Transformer capacity is then added (up to four transformers) based on projected load growth in the area served by the A-bank substation. By the time a fourth transformer bank is added at an A-bank substation, the existing subtransmission facilities are divided into two separately operated electrical systems (termed a "split system") with each system being served by two transformers. These two separately operated subtransmission "radial" systems are still both served from the same A-bank substation. However, because these subtransmission systems are electrically separate from each other, they are planned for independently as it relates to capacity, reliability, and resiliency. Figure 3-3 and Figure 3-4 illustrate the differences between A-bank substations that serve a single subtransmission system and those that serve split systems. The Valley System is an example of a split system with two electrically separate subtransmission systems (Valley North and Valley South) served from the same A-bank substation, Valley Substation.

There are several reasons related specifically to reliability and resiliency for splitting systems by the time that a fourth transformer is added. These reasons include reducing how many customers are affected when an electrical disturbance event occurs and limiting short-circuit current values that could otherwise increase beyond equipment ratings when four transformers operate electrically in parallel. Per SCE subtransmission planning guidelines discussed in Section 4.3 of this study, it is SCE's practice, consistent with good engineering practice for radial system design, to incorporate system tie-lines into a split system design to ensure that each of the newly formed radial electrical systems maintains the ability to transfer distribution substations from one system to another. These system tie-lines are commonly used to address system conditions resulting from planned or unplanned outages of either an A-bank substation transformer or of subtransmission

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[34] Using standard transformer sizes allows for spare transformers to be maintained in inventory at strategic locations, which minimizes inventory requirements and maximizes the efficiency in mobilizing replacements following transformer failures.

lines to avoid overload conditions on the remaining A-bank transformers and/or subtransmission lines within that system and to provide operational flexibility. The Valley South System currently does not have system tie-lines as elaborated on and described in Section B.2 of Appendix B.

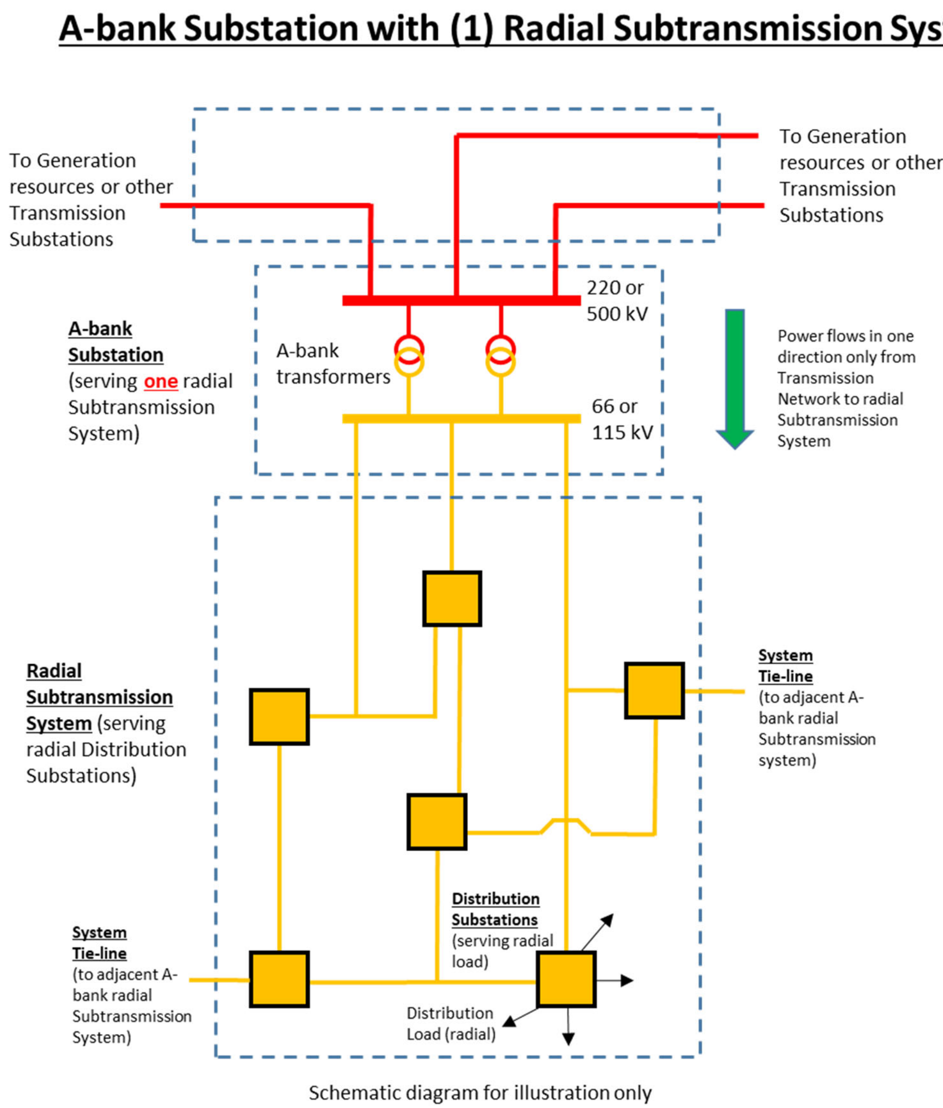

Figure 3-3 – A-bank Substation with a Single Radial Subtransmission System

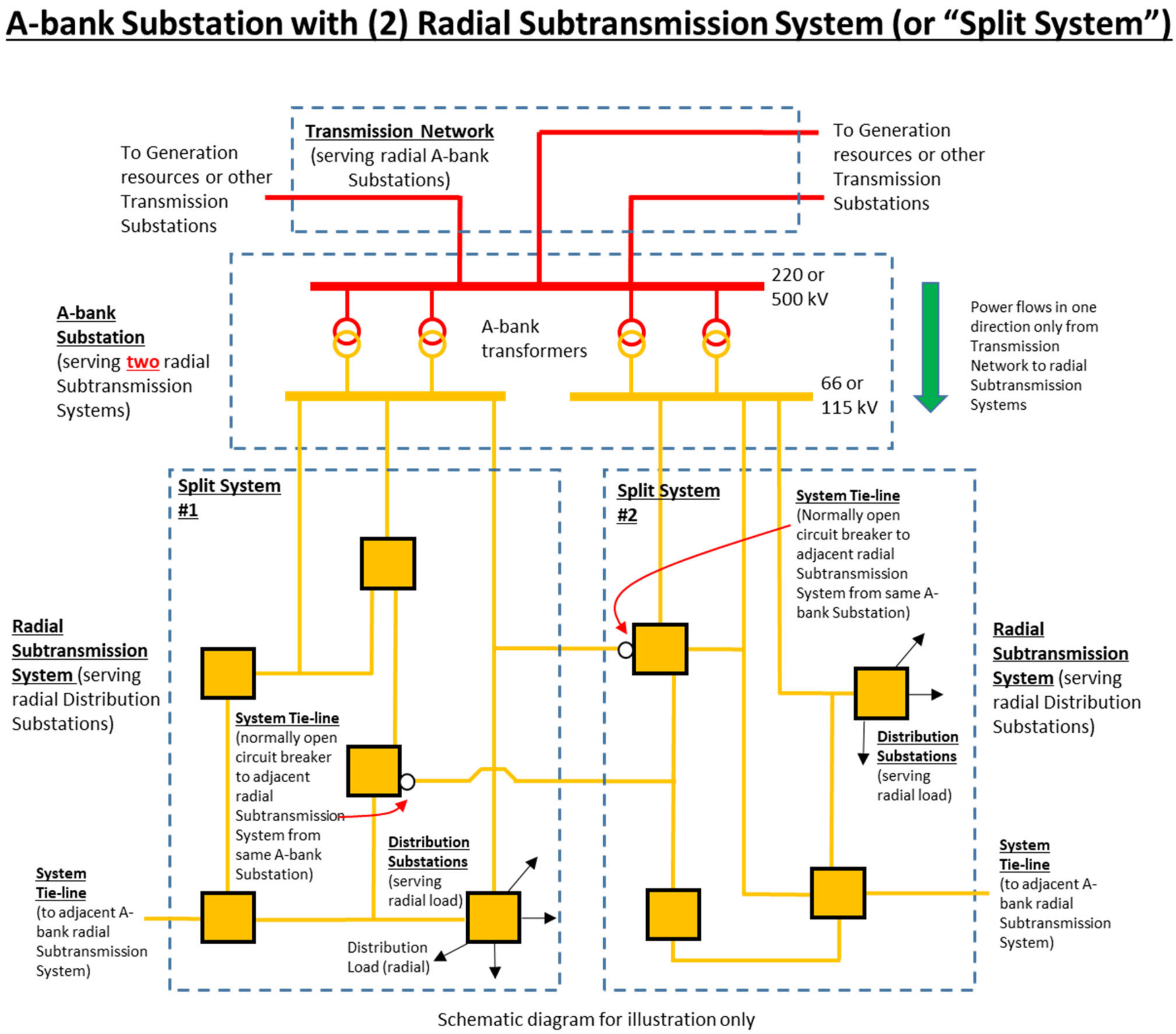

Figure 3-4 – A-bank Substation with Split Radial Subtransmission Systems

3.3. Comparison of Valley South System with Other SCE Subtransmission Systems

SCE has a total of 56 distinct subtransmission electrical systems served from its 43 A-bank substations (resulting from a portion of its A-bank substations operating in a "split system" configuration). Of these 56 electrical systems, all but four are served in a radial[35] manner. The Valley South System and the Valley North System are split systems served by the Valley A-bank Substation.

The Valley South System is unique in that it is the *only* one of these 56 distinct electrical systems without system tie-lines to another 115 kV subtransmission system. This condition resulted from a unique combination of events in the system's history that is chronicled in the *History of the Valley Systems* in Appendix B of this Planning Study. The lack of tie-lines that resulted from this evolution was not considered desirable or acceptable for the long term; however, due to the significant load growth that was occurring, SCE took temporary exception to its preferred, consistent, and prudent practice of including system tie-lines in its design of radial systems with an expectation that a long-term solution would be planned and implemented.

SCE provided data on Valley South System characteristics that challenge reliability and/or resiliency[36], contributing to the likelihood of occurrence and/or impact of events that lead to loss of service to customers. These characteristics, when compared to SCE's other 55 subtransmission systems, demonstrate that no other SCE subtransmission planning area has a similar cumulative combination of characteristics that lead to the reliability and resiliency challenges that the Valley South System faces.

The reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity margin, configuration, and size that make the Valley South subtransmission system much more vulnerable to future reliability problems than any other SCE subtransmission system. Specifically, in its current status, the Valley South System operates at or very close to its maximum operating limits, has no connections (system tie-lines) to other systems, and represents the largest concentration of customers on a single substation in SCE's entire system. These characteristics threaten the future ability of the Valley South System to serve load under both normal and abnormal system conditions. In the specific case of a catastrophic event (abnormal condition such as a major fire or incident at Valley Substation) SCE's ability to maintain service or to restore power in the event of an outage is significantly limited by the concentration of source power in a single location at Valley Substation.

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[35] There are two sets of networked substations included in the 56 distinct systems: the Antelope and Bailey 66 kV Systems and the Victor and Kramer 115 kV Systems. In each example, both of the electrical systems are located adjacent to each other and serve largely rural areas. In lieu of constructing a significant amount of new subtransmission lines to address any identified issues (under normal or abnormal system conditions) within each of the systems independently, reliability issues associated with lack of system ties between the split systems were able to be resolved by connecting the Antelope and Bailey Systems together and the Victor and Kramer Systems together and operating each in parallel with the CAISO-controlled bulk electric system.

[36] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B.

4.0 Planning Criteria and Process

4.1. Planning Process

The first step in SCE's annual distribution and subtransmission planning process is to develop peak load and DER forecasts for all distribution circuits, distribution substations, subtransmission lines, and load-serving transmission substations (A-bank substations). These forecasts span 10 years and evaluate peak load conditions to determine the impacts to SCE's distribution and subtransmission systems. Historically, peak load conditions were sufficient to determine criteria violations; however, as a result of increasing DER penetration in the distribution system, traditional peak load studies are no longer sufficient to capture criteria violations that may occur due to the DERs that impact the system outside of peak hours. As such, SCE now also evaluates high DER output conditions that are not coincident with peak load and the mitigations necessary to address criteria violations.

The SCE load forecast is derived from SCE's disaggregation of the California Energy Commission (CEC) annual California Energy Demand (CED) Forecast as part of the annual Integrated Energy Policy Report (IEPR) proceeding (see Section 5.0 Load Forecast). This forecast is provided at the bulk transmission level and is disaggregated down to the subtransmission and distribution levels.[37] DERs that consume and produce energy are incorporated at the lowest system level (e.g., distribution circuit level), and are used in the peak load forecast, as well as the separate high DER penetration analysis. After the load and DER forecasts are developed, the next step in SCE's planning process is to perform the necessary technical studies that determine whether the projected forecasts can be accommodated using existing infrastructure. SCE uses planning criteria as the basis for designing a reliable system. The planning criteria are based on equipment loading limits (termed "planned loading limits") that consider the effects of loading on thermal, voltage, and protection limits under normal and emergency conditions. The analysis includes comparing the expected forecast peak load under peak heat storm conditions over a 10-year period to these established planned loading limits.

When studies show that peak load or DER impacts are expected to exceed planned loading limits, potential solutions are identified to mitigate the risk of overloading equipment, which in turn serves to decrease the probability of failures and service interruptions that might affect many customers. As part of identifying solution alternatives, SCE first seeks to maximize the utilization of existing assets before developing projects that require capital expenditures to install new infrastructure.

4.2. Subtransmission Planning Criteria

SCE's Subtransmission Planning Criteria and Guidelines provide a basis for designing a reliable Subtransmission System taking into account continuity of service, as affected by system facility outages, and capital investment.[38] The Subtransmission Reliability Criteria are provided below.

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[37] For details on this methodology, see Section 3.0 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.

[38] SCE Subtransmission Planning Criteria and Guidelines 9/2015.

At a minimum, SCE's Subtransmission System shall be designed in order that the following occurrences do **not** result from a Likely Contingency[39]:

- Interruption of load except:
  - When served by a single Subtransmission System Component.
  - In the case of an Overlapping Outage of two subtransmission lines serving less than Major Subtransmission Load.
- Automatic under-frequency shedding of load.
- Operation of Subtransmission System Components at ampacity or power levels that exceed Likely Contingency Ratings.
- Voltage drop of more than 5.0% on high side substation load buses after available corrective action with Load Tap Change, switched capacitors, or voltage regulators.

These criteria are used when designing subtransmission systems and form the minimum acceptance criteria for performance of such systems in system studies. Unlikely Contingencies[40] are also studied to determine the effect on system performance. When such contingencies result in load interruption, loss of a generating source, risk of damage to SCE's electric facilities, or risk of Cascading Outages, projects to minimize the problems are considered. For all projects, assessments include estimated costs or benefits due to expected reliability levels provided by the alternatives under consideration.

4.3. Subtransmission Guidelines

The Subtransmission Guidelines provide general planning and design guidelines for components and operation of the subtransmission system. Components include subtransmission circuits, substations, transformers, busses, circuit breakers, protection devices, and volt-ampere reactive (VAR) control devices. Operational guidelines apply to practices such as load rolling, VAR correction, voltage regulation, curtailment, and relaying. Rather than exhaustively list the guidelines and requirements, those pertinent to the problem statement as it relates to the Valley South System are considered in this section, and are provided in Table 4-1. Note that as described in Table 4-1, SCE has had to take temporary exceptions to the Subtransmission Planning Criteria and Guidelines in order to comply with the mandate to continue to provide electricity in the face of significant local area economic growth and an expanding customer base while a comprehensive long-term solution was developed, permitted, and implemented.

[39] A Likely Contingency is defined as follows: One generating unit is off/unavailable and then any one of the following occurs: (1) an outage of a single Subtransmission System Component; (2) an unscheduled outage of a single generating unit; (3) a simultaneous outage of two subtransmission circuits on the same pole and exposed to vehicular traffic when these circuits are the sole supply for a substation.

[40] An Unlikely Contingency is defined as follows: One generating unit is off/unavailable and then any one of the following occurs: (1) simultaneous outage of two subtransmission circuits; (2) an overlapping outage of any two generators or one generator and one line.

Table 4-1– Subtransmission Guidelines Related to Valley South

Section	Guideline	Relevance to Valley South
2.2.1	Sufficient 220/66 kV, 220/115 kV, or 500/115 kV transformer capacity will be provided, or adequate subtransmission tie line capacity with circuit breaker switching capability will be planned to limit or reduce the transformer loading in the event of a transformer bank outage.	The Valley South System is projected to exceed existing transformer capacity in 2022, and currently has zero tie-line capacity to limit transformer loading in the event of a transformer bank outage coincident with peak loading.
2.3.1	For the purpose of planning, 500 kV banks which serve radial load shall be planned as A-Banks, except using AA-Bank loading limits.	Valley Substation is an A-Bank substation serving radial load. Transformers are rated using AA-Bank loading limits.
2.3.1.1	Short-Term (1-hour) Contingency Loading Limit Maximum rating: Up to 160% of the Nameplate Rating provided that the load can be reduced to the Long-Term (24-hour) Emergency Loading Limit in one hour.	The Valley Substation spare transformer is currently utilized as necessary to temporarily relieve load on the two normally in-service Valley South transformers during peak loading. The spare is placed into service whenever the load on the substation exceeds 80% (896 MVA), in order to keep the total load on a single transformer under 160% (i.e., the Short-Term Contingency Loading Limit) in the event there is an unplanned outage of one of the transformers.

Section	Guideline	Relevance to Valley South
2.3.1.2	One three-phase 500/115 kV spare transformer will be provided on site at each 500/115 kV substation.	The Valley Substation spare transformer (which is shared among Valley North and Valley South) is currently utilized as necessary to temporarily relieve load on the two normally in-service Valley South transformers during peak loading. Thus, during peak loading scenarios, the spare transformer is not immediately available to serve its intended function as a replacement unit for an out-of-service transformer, and is therefore not available at all times if needed as a spare for the Valley North System.
2.3.2.1.A	All Facilities in Service: Adequate transformer capacity shall be provided to serve the maximum coincident customer loads (including 1-in-5 year heat storm conditions)…	Valley South System transformer capacity is projected to be exceeded by year 2022.
2.3.2.1.B	Contingency Outages: Adequate transformer capacity and load rolling facilities shall be provided to prevent damage to equipment and to limit customer outages to Brief Interruptions…	The Valley South System currently has no system tie-lines to any other system, and therefore has zero tie-line capacity available to roll load.
2.3.2.4	To avoid Protracted Interruption of Load, tie lines with normally open supervisory controlled circuit breakers will be provided to restore service to customers that have been dropped automatically to meet short-term Likely Contingency loading limits, and to reduce A-Bank load to the long-term Likely Contingency loading level.	The Valley South System currently has no system tie-lines to any other system, and therefore has zero tie-line capacity.

5.0 Load Forecast

SCE annually forecasts load, on a 10-year planning time horizon, to assess system capacity and reliability given projected future load growth. To validate this load forecast, Quanta Technology was contracted to perform two independent load forecasts. The load forecasts prepared for this study indicate that, under 1-in-5 year heat storm conditions, the Valley South System will exceed the ultimate design capacity of the existing transformers as early as the year 2022.

5.1. SCE Load Forecast Methodology

SCE develops its load forecast as the first step in its distribution and subtransmission planning process. The forecast spans 10 years and determines peak load using customer load growth and DER forecasts, including energy efficiency, energy storage, demand response, plug-in electric vehicles, and distributed generation such as solar photovoltaic (PV). The forecast is based on peak load collected from historical data, normalized to a common temperature base in order to account for variations in peak temperatures from year to year. In addition to a normalized 10-year forecast, the methodology also produces a forecast adjusted for 1-in-5-year heat storm conditions.

SCE uses the CEC's IEPR-derived CED forecasts to ultimately determine its base load growth forecast at the distribution circuit level. As the IEPR forecast is provided to the utilities at a system or large planning area level, SCE must disaggregate this forecast to provide the granularity necessary to account for local-area specific electrical needs. SCE utilizes its own customer data from its advanced metering infrastructure (AMI) to inform its disaggregation of the CEC IEPR forecast. Where appropriate, SCE may also incorporate additional load growth that may not have been fully reflected in the CED forecasts (e.g., cannabis cultivation load growth).[41]

A detailed discussion of SCE's Load Forecast is included in the supplemental data request submittals.[42]

5.2. Quanta Technology Load Forecast Methodology

The first method Quanta Technology used to forecast load is referred to as the Conventional method. Historical substation load data provided by SCE was normalized to a peak 1-in-2 year temperature for the region in order to place all distribution substation load data at the same

[41] SCE participates in the CPUC's Distribution Forecasting Working Group to discuss, review, and approve, among other topics, the methodologies to disaggregate load and DERs to the distribution circuit level.
[42] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.

reference temperature.[43] These adjusted data were then used to compute horizon-year[44] load growth based on curve-fitting. The growth in load was then adjusted further by considering an increase in load due to non-traditional developments (e.g., cannabis cultivation), as well as an increase in load due to incremental growth in residential density (i.e., more multi-family homes than single family homes are built). Growth of DERs was accounted for by considering that these resources are part of historic load data and considering that the historic trend of DER development will continue in the future.

For each distribution substation, a Gompertz curve fit was developed to estimate the forecasted load at all intermediate years between 2018 and the horizon-year (i.e., 2048). The aggregate of all distribution substation forecasts was then used to compute a coincident horizon year load[45] for the Valley North and Valley South Systems. The aggregate forecasts were then adjusted to account for 1-in-5 year heat storms at the Valley North and South System level.

The second method Quanta Technology used to forecast load is referred to as Spatial Load Forecasting (SLF). This method involves the forecasting of peak load, customer count, and customer energy consumption within a particular needs area. The geographical region is divided into sub-areas, each of which is analyzed individually to forecast customer count, peak electrical demand, and annual customer energy consumption. Customer count forecasts are based on an analysis of zoning and land-use data within the sub-area. Customer peak demand and energy consumption is based on actual AMI data and a consideration of typical area building energy consumption (e.g., kWh per residential customer, kWh per commercial customer, etc.). Non-traditional factors that may affect electrical load growth, such as photovoltaic (PV), electric vehicle (EV) adoption, and energy efficiency (EE) are incorporated by disaggregating the CED forecast and applying appropriate growth factors at the smallest level of sub-division. Finally, the results are aggregated to forecast the net peak load on the system.

5.3. Load Forecast Results

Figure 5-1 shows the results of the three load forecasts. The red horizontal line in the graph represents the ultimate system design capacity of the Valley South System. The results show that all of the load forecasts predict that the Valley South transformers will overload in 2022.

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[43] Load is highly correlated to temperature. As the peak demand for a given year may not fall on the exact day that a peak temperature is recorded, the peak load for each year of historical data must be normalized to a common temperature base in order to compare load from year to year. This is done using a 1-in-2 year temperature, consistent with industry practice.

[44] In order to ensure optimal accuracy of the curve-fitting techniques used, a horizon year must be chosen. Typically, this horizon year is chosen to be very far into the future in comparison to the time period under study. For this analysis, a horizon year of 2048, or 30 years into the future, was chosen.

[45] The actual aggregate produced a non-coincident horizon year load at the Valley North and Valley South systems. Coincidence factors were applied to adjust the loads to represent the total coincident load. See Quanta Technology Report *Load Forecasting for Alberhill System Project* for further discussion.

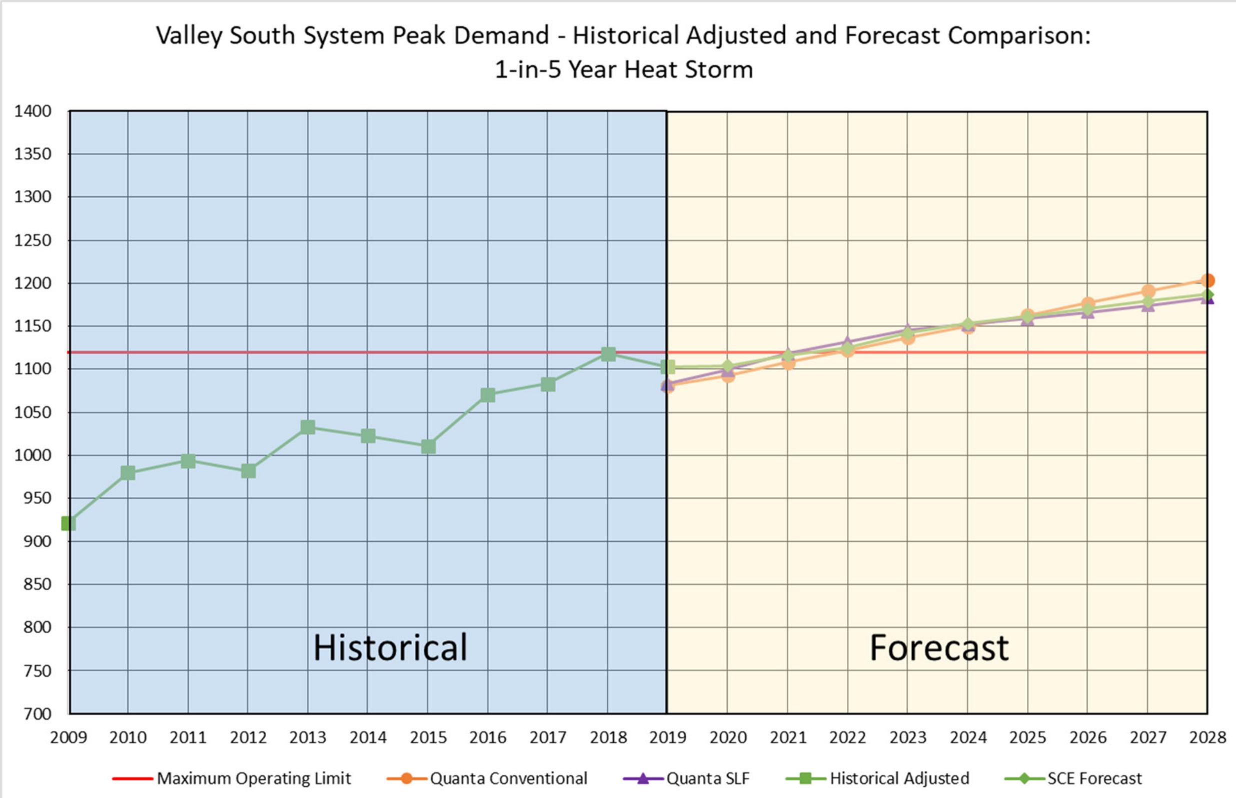

Figure 5-1 – Valley South System Peak Demand, Historical and Forecast

5.4. Load Forecast Extension to 30 Years

To support SCE's cost-benefit analysis, the Quanta SLF was used to forecast load beyond the 10-year planning horizon. Recall that the SLF looks at small, discrete areas (150 acres in size) and considers geo-referenced individual customer meter data (peak load), local land use information, and county and city master and specific development plans and thus is particularly well-suited among load forecasting methods for long term forecasts. Similar to the Quanta Technology Conventional Forecast, curve-fitting techniques were used for each of these small, discrete areas to forecast load for a full 30 years, roughly corresponding to the economic life of conventional transmission and distribution assets that make-up the ASP and all of the alternatives that meet the project objectives. Quanta Technology developed three forecasts based on this spatial analysis to support both a base case cost-benefit analysis as well as high and low load cases for sensitivity analysis. These three cases reflect varying rates of DER adoption. Because both upward and downward trends in economic conditions are expected over a 30-year forecast period, no additional variations in the forecasts were incorporated based on economic factors.

The first forecast ("Spatial Base") incorporates future DERs by assuming a continuing rate of DER adoption reflected in historical load growth and thus does not directly reflect future deviations in the existing trends in on-peak PV, building and vehicle electrification, energy storage (ES), energy efficiency (EE), or demand response (DR). Although it is possible that enhanced electrification rates could exceed future PV, ES, EE, and DR growth, for the purpose of this cost-benefit analysis, this Spatial Base forecast is considered to be the high load forecast, reflecting a scenario where increased growth rates for electrification effectively offset increases in growth rates for load-reducing DERs.

A mid-range ("Spatial Effective PV[46]") load forecast was developed by considering continuing changes in growth rates of DER adoption as reflected in the 2018 CED forecast. The adopted 2018 forecast only goes out to the year 2030. In order to extend IEPR load growth considerations to 2048, a regression method with a saturation tendency was applied to the individual IEPR-derived PV, EV, EE, and DR load impact forecasts. The forecast DER growth rates were determined through regression analysis, then applied to reduce the forecast load to account for expected increases in DER adoption beyond those reflected in historical trends. The Spatial Effective PV forecast also includes an adjustment to account for the expected effective on-peak contribution of installed customer-sited solar PV capacity for peak load reduction, adjusting the amount of generation based on time-of-day and general historical reliability metrics. This forecast is used as a base-case for the cost-benefit analysis as it is considered to represent the most likely future long-term load forecast scenario.

Finally, a low load forecast case ("Spatial PVWatts") was developed by incorporating the unadjusted extended CED forecast, using the IEPR-derived PV forecast (derived from the National Renewable Energy Laboratory DOE PVWatts PV generation modeling program) directly without the SCE adjustments for dependability. This low forecast is considered to be reflective of a future scenario where PV adoption, either on-peak or load-shifting, significantly outpaces electrification.

Figure 5-2 shows the three forecasts for the Valley South System used in the Uncertainty Analysis. For details on the 30-year extension of the load forecast, see Quanta Technology Report *Benefit Cost Analysis of Alternatives.*

[46] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A and Quanta Technology Report *Load Forecasting for Alberhill System Project* for a detailed description of Spatial Effective PV.

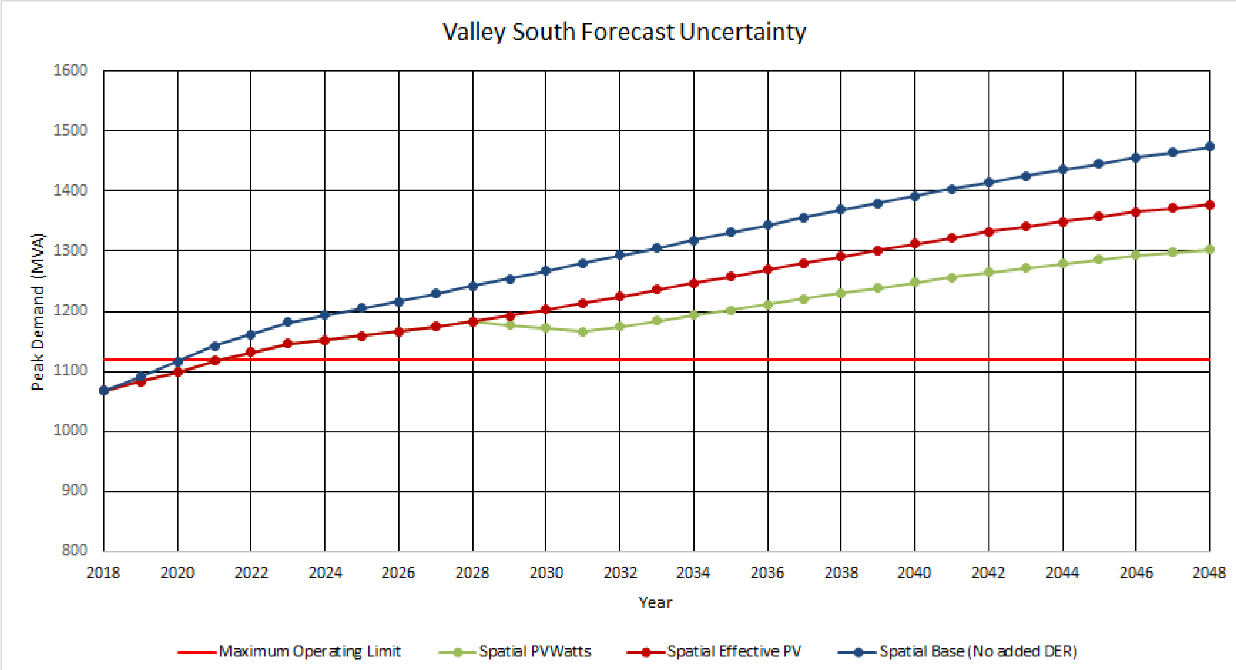

Figure 5-2 – 30-year Load Forecast with Uncertainty

The three forecasts were used to perform cost-benefit analyses for each of the alternatives, in order to assess if and how the results of the cost-benefit analysis would vary given a variance in the 30-year forecast. The alternatives were expected to score slightly differently based on either additional or fewer benefits accrued. For instance, when using the higher forecast (Spatial Base), alternatives that include capacity margin would tend to accrue more benefits. Conversely, in the lowest forecast (PV Watts), alternatives that are lower in cost may score higher, as those alternatives with capacity margin would accrue fewer benefits. Higher or lower forecasts also affect the reliability and resiliency related metrics in the cost benefit analysis as more or fewer customers are affected by the outage scenarios associated with the cost benefit metrics and capacity margin can affect the flexibility to mitigate these scenarios. The results of this uncertainty analysis are in Section 8.0.

6.0 Alternatives Development and Screening

SCE developed a comprehensive list of preliminary project alternatives based on a variety of inputs including: the direction of the CPUC in the Alberhill decision[47]; the previous assessment of alternatives in the Alberhill EIR; public and stakeholder engagement; and professional expertise. Preliminary project alternatives were evaluated qualitatively against project objectives and quantitatively using reliability and resiliency metrics to allow for a comparative assessment. All alternatives were designed to serve load at least through the horizon of the 10-year load forecast in accordance with the project objectives and SCE subtransmission planning criteria.

A total of 16 project alternatives were initially considered, including three Minimal Investment Alternatives, seven Conventional Alternatives (including the Alberhill System Project), one Non-Wires Alternative (NWA), and five Hybrid Alternatives that combine Conventional and NWA alternatives. This section briefly introduces the project alternatives, describes the performance metrics used for comparison, and presents the results.

6.1. Project Alternatives

Project alternatives were grouped into four categories based on the overall approach of the alternative. Minimal Investment Alternatives were considered as solutions that utilize existing equipment or make modest capital investments of <$25M to mitigate the issues under evaluation. Conventional Alternatives include transmission and/or subtransmission line and substation build outs, as well as system tie-lines to neighboring systems. NWAs include, for example, BESS in both centralized (transmission system level) and distributed (distribution system level) installations. Hybrid Alternatives are those that combined Conventional Alternatives with NWA. Appendix C provides a more detailed overview of each of the alternatives that were ultimately considered in the cost benefit analysis of alternatives.

The Conventional Alternatives were designed to accommodate the capacity need for the expected load forecast for the ten-year planning period but in most cases due to practical limitations[48] in the number of substations that could be transferred, the Conventional Alternatives were not able to satisfy the needs for the full 30 years of the cost-benefit analysis. In these cases, the shortfall in capacity is represented in the cost -benefit analysis as a reduction in benefits of the proposed solution. Alternatively, in the case of Hybrid Alternatives, the future capacity shortfall was met by incorporation of NWAs to the initial Conventional Alternatives.

NWAs are considered at both the subtransmission level (Centralized) or at the distribution level (Distributed) and, for the purpose of this Planning Study, BESS are used as a surrogate for all DERs that might ultimately be incorporated in Hybrid Alternatives. From a system perspective,

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[47] The CPUC directed SCE to supplement the existing record with "Cost/benefit analysis of several alternatives for: enhancing reliability and providing additional capacity including evaluation of energy storage, distributed energy resources, demand response or smart-grid solutions." (Decision 18-08-026)

[48] Practical considerations include the ability of the adjacent system to accommodate the load transfer as well as engineering judgement on the cost-effectiveness of larger scale system modifications required to increase the number of transferred substations.

energy storage and other DERs similarly serve to reduce system level loading at the level in the system in which they are installed and BESS represents a NWA option with minimal uncertainty from a cost and implementation risk standpoint (See Section 9.10). When the need date for the incremental capacity needs approaches, SCE can, under the appropriate regulatory framework at the time, build or source available front-of-the-meter and behind-the-meter DER technologies at market prices to meet these incremental capacity needs.

SCE also developed Hybrid Alternatives to satisfy the incremental capacity needs including NWAs that could be introduced incrementally as the remaining capacity need develops over time (e.g., Valley South to Valley North and Distributed BESS in Valley South). In such case, the additional capacity benefits are accrued but at a higher cost of meeting the capacity shortfall through NWAs. Each Hybrid alternative includes subtransmission scope which addresses some portion of the capacity need of the project by either transferring some number of the Valley South System distribution substations to either a new source substation or to an adjacent subtransmission system that has capacity margin. The number of substations that can be transferred in a solution is limited by the required scope of subtransmission work within the Valley South System to implement the transfer[49] and, in the case of a transfer to an existing adjacent subtransmission system, the capacity margin that exists to serve this new load in that adjacent system.

6.1.1. Minimal Investment Alternatives

Utilizing spare transformer for the Valley South System

This alternative considered temporarily placing the spare 500/115 kV transformer at the Valley Substation in service as needed to service the Valley South System under peak loading conditions, essentially continuing the current practice of the mitigation plan in place today. This alternative would also involve installation of a new spare 500/115 kV transformer (for a total of six transformers within Valley Substation). Implementation of this alternative would be challenging, if not infeasible, due to physical space constraints of Valley Substation and electrical system limitations associated with operating in this configuration.[50]

Operating existing Valley South System transformers above normal ratings

SCE's Subtransmission Planning Criteria and Guidelines allow operation of A-bank transformers above nameplate for periods of limited duration. This alternative involves utilizing the Valley South System transformers above normal ratings (i.e., intentionally operate them above the manufacturer nameplate ratings) to serve load in the Valley South System under peak loading conditions.

[49] The subtransmission work that is associated with this load transfer must also leave lines in place to serve as system tie-lines between systems thus satisfying the system tie-line project objective.

[50] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item H for details related to short-circuit duty with three or more transformers operating in parallel at Valley Substation.

Load Shedding Relays

This alternative would utilize load shedding to maintain system reliability during stressed system conditions that result from peak load conditions that would otherwise exceed the ratings of the Valley South System transformers.

6.1.2. Conventional Alternatives

Alberhill System Project

The ASP would involve the construction of a new 1,120 MVA 500/115 kV substation in Riverside County. Approximately 3.3 miles of new 500 kV transmission line would be constructed to connect to SCE's existing Serrano-Valley 500 kV transmission line. Construction of approximately 20.4 miles of new 115 kV subtransmission line would be required to transfer the Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb Substations to the new Alberhill System.

SDG&E

This alternative would construct a new 230/115 kV system, anchored by a substation located in SCE territory, but provided power by SDG&E's 230 kV System.[51] SCE's existing Pechanga and Pauba Substations would be transferred to the new 230/115 kV system, which would be powered by looping in the existing SDG&E Talega-Escondido 230 kV transmission line. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

SCE Orange County

This alternative would construct a new 220/115 kV system, anchored by a new substation located in SCE territory. SCE's existing Stadler and Tenaja Substations would be transferred to this new system, which would be powered by looping in SCE's existing SONGS-Viejo 220 kV transmission line. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

Menifee

This alternative would construct a new 115 kV system, anchored by a new 500/115 kV substation at or near the existing site of the third-party owned Inland Empire Energy Center (IEEC) generation facility. SCE's existing Newcomb and Sun City Substations would be transferred to

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[51] For the purposes of this Planning Study, the designation of SCE's 220 kV system voltage and the designation of SDG&E's 230 kV system voltage can be considered equivalent.

this new system, which would be powered by looping in SCE's existing Serrano-Valley 500 kV transmission line.

Mira Loma

This alternative would construct a new 220/115 kV system, anchored by a new 220/115 kV substation located in SCE territory near the existing Mira Loma Substation. SCE's existing Ivyglen and Fogarty Substations would be transferred to this new system, which would be powered by looping in one of SCE's existing 220 kV transmission lines serving Mira Loma Substation. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

VS to VN (Valley South to Valley North)

This alternative would transfer SCE's existing Newcomb and Sun City Substations from the Valley South System to the Valley North System. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

VS to VN to Vista (Valley South to Valley North to Vista)

This alternative would construct new 115 kV lines connected to the Valley North System bus at Valley Substation and would transfer SCE's existing Newcomb and Sun City Substations from the Valley South System to the Valley North System. Additionally, SCE's existing Moreno Substation would be transferred from the Valley North System to SCE's adjacent Vista 115 kV System by utilizing existing system ties between the Valley North System and the Vista 115 kV System. To perform the transfer of substations and to restore the connectivity and reliability of the 115 kV system following the transfer, new 115 kV line construction would be required.

6.1.3. Non-Wires Alternatives

Centralized BESS in VS

This alternative would install two 115 kV connected BESS, one each near SCE's existing Pechanga and Auld Substations.

Although this alternative on its own does not meet all of the project objectives (specifically the creation of system tie-lines), SCE carried forward the Centralized BESS in VS in the analysis in order to investigate the relative cost-benefit performance of a BESS solution alone and when paired with a Conventional Alternative to demonstrate the benefit of the system tie-lines.

6.1.4. Hybrid Alternatives

Hybrid alternatives were developed by combining Conventional Alternatives and NWAs. The conventional solutions were chosen based on their ability to meet the 10-year load forecast and then paired with BESS to satisfy incremental capacity needs that develop over time.

Capacity margin above and beyond capacity provided by new transformation or the transfer of load in each of the Hybrid Alternatives is initially achieved through the construction of system tie-lines, as tie-lines can be engaged to alleviate a potential thermal or voltage violation on a subtransmission line. Then, consistent with planning criteria under normal (i.e., N-0) conditions, the BESSs were sized to mitigate capacity shortfalls in the Valley South and Valley North Systems over the 30-year load forecast. The initial battery installation therefore occurs when there is a projected capacity shortfall under normal conditions. This initial installation varies among the alternatives and is driven by the amount of margin that is provided by the corresponding conventional scope.

Unlike Conventional Alternatives, BESS include both a power (megawatt or MW) and energy (megawatt-hour or MWh) sizing component to meet capacity shortfalls. The power component corresponds to the amount of peak demand in excess of the transformer capacity in the systems, and the energy component corresponds to the total energy that would otherwise go unserved during times in which the transformer capacity is exceeded. The power component of the BESS was augmented for N-1 conditions (consistent with the Subtransmission Planning Criteria) by including an additional 10 MW of capacity.[52] Similarly, the energy component of the BESS was augmented for battery degradation (2% per year), and for N-1 conditions.[53]

The initial, and each subsequent BESS installation, is sized to meet the projected capacity need in the system for five years. For example, a BESS installed in 2037 would mitigate the projected capacity shortfall through 2042 at which point additional BESS capacity would be added. The battery installation schedules for each Hybrid Alternative are provided in Appendix C.

Valley South to Valley North and Distributed BESS in VS

This alternative would augment the Valley South to Valley North Alternative with three smaller 12 kV connected BESSs throughout the Valley South System, at the Auld, Elsinore, and Moraga 115/12 kV distribution substations. The BESS would be required in the 2043 timeframe. The size and need date of each BESS was determined by the local need. Note that from a system benefit perspective this alternative would be similar to the case where a specific, targeted Demand Side Management (DSM) or other Distributed Energy Resource (DER) program were to be implemented at the distribution system level.

SDG&E and Centralized BESS in VS

This alternative would augment the SDG&E Alternative with a centralized 115 kV connected BESS located near SCE's existing Auld Substation. The BESS would be required in the 2039 timeframe.

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[52] SCE expects that the BESS installations would be comprised of modules of batteries connected to the system in blocks of 10 MW each. Typical N-1 assessments consider the unavailability of single system components (e.g., transformers, lines, generating units) and thus in this scenario, a single BESS module was considered unavailable.

[53] A duration of 5 hours is assumed for N-1 conditions. This equates to an additional 50 MWh (based on a 10 MW rating) of energy in each system (i.e., Valley South, Valley North, or both, depending on the alternative).

Mira Loma and Centralized BESS in VS

This alternative would augment the Mira Loma Alternative with a centralized 115 kV connected BESS located near SCE's existing Pechanga Substation. The BESS would be required in the 2031 timeframe.

VS to VN and Centralized BESS in VS and VN

This alternative would augment the VS to VN Alternative with two separate centralized 115 kV connected BESS installations (one near SCE's existing Pechanga Substation and one near SCE's existing Alessandro Substation). The BESS would be required in the 2043 and 2037 timeframes, respectively.

VS to VN to Vista and Centralized BESS in VS

This alternative would augment the VS to VN to Vista Alternative with a centralized 115 kV connected BESS near SCE's existing Pechanga Substation. The BESS would be required in the 2043 timeframe.

6.2. Evaluation of Alternatives Using Project Objectives

Each project was qualitatively evaluated against the Project Objectives detailed in SCE's Application for the ASP.

- Serve current and long-term projected electrical demand requirements in the Electrical Needs Area.
- Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer substations from the current Valley South System.
- Transfer (or otherwise relieve[54]) a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through the 10-year planning horizon.
- Provide safe and reliable electrical service consistent with the Company's Subtransmission Planning Criteria and Guidelines.
- Increase electrical system reliability by constructing a project in a location suitable to serve the Electrical Needs Area (i.e., the area served by the existing Valley South System).
- Meet project need while minimizing environmental impacts.
- Meet project need in a cost-effective manner.

Based on SCE's evaluation against these objectives, the three Minimal Investment Alternatives were eliminated from further quantitative analysis due to meeting only one or none of the project objectives. The Centralized BESS in Valley South alternative by itself also falls short of meeting the project objectives; however, as discussed, SCE carried forward a BESS-only alternative in the analysis in order to investigate the relative cost-benefit performance of these BESS solutions alone

[54] Clarified from original objectives so as not to preclude non-wires alternatives.

and when paired with a Conventional Alternative to demonstrate the benefit of the system tie-lines. All of the Conventional Alternatives and Hybrid Alternatives were confirmed to meet the project objectives.[55]

6.3. System Performance Metrics

In order to compare the alternatives to one another on a quantitative basis, a time-series power flow analysis was performed for each alternative carried forward. The system was modelled and analyzed using the GE-PSLF (Positive Sequence Load Flow) analysis software. PSLF is a commonly used software tool used by power system engineers throughout the utility power systems industry, including many of the California utilities and the CAISO, to simulate electrical power transmission networks and evaluate system performance. The tool calculates load flows and identifies thermal overload and voltage violations based on violation criteria specified by the user. In this case, the model considers the existing Valley South and Valley North Systems and includes the pending Valley-Ivyglen and VSSP projects[56] which are both in construction and anticipated to be completed in 2022 and 2021, respectively. The 8,760 hour load shape of each system was utilized and scaled according to the 1-in-5 year adjusted peak demand given by the load forecast for each of the years under study. The specified analysis criteria listed below are consistent with the SCE subtransmission planning criteria described in Section 4.0 of this Planning Study.

- No potential for N-0 transformer overloads in the system.
- Voltage remains within 95%-105% of nominal system voltage under N-0 and N-1 operating configurations.
- Voltage deviations remain within established limits of +/-5% post contingency.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.

For each hour analyzed, the model determines how much, if any, load is required to be transferred to an adjacent system (if system tie-line capacity is available) or dropped (if system tie-line capacity is not available) in order to maintain the system within the specified operating limits. The dropped (or unserved) load is summed over the 8,760 hours of the year, for base and contingency conditions, over a 30-year span of the Planning Study to provide the basis for the majority of the metrics described below.

The alternatives were evaluated using the following system performance metrics. For each metric, the incremental improvement over the baseline was quantified for each of the project alternatives. Full details of these analyses can be found in Quanta Technology Report *Benefit Cost Analysis of Alternatives*.

- Load at Risk (LAR)
  - Quantified by the number of megawatt-hours (MWh) at risk during thermal overload and voltage violation periods.

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[55] Although the Conventional and Hybrid Alternatives currently meet the capacity requirements identified in the 10-year forecast, once licensed and constructed, several alternatives will no longer be able to meet this requirement as the load continues to increase beyond 2028.

[56] Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018).
VSSP, Valley South 115 kV Subtransmission Project, CPUC Decision 16-12-001 (issued December 1, 2016).

- Calculated for N-0 and all possible N-1 contingencies.
    - For N-1 contingencies, credits the available system tie-line capacity that can be used to reduce LAR.
- Maximum Interrupted Power (IP)
    - Maximum power to be curtailed during thermal overload and voltage violation periods.
    - Calculated for N-0 and N-1 contingencies.
- Losses
    - Losses are treated as the active power losses in the Valley South System. New lines introduced by the scope of a project are included in the loss calculation.
- Flexibility 1 (Flex-1)
    - Accumulation of LAR for all N-2 contingencies. N-2 contingencies are only considered for lines that share common structures.
    - Credits the available system tie-line capacity that can be used to reduce LAR.
    - Results for each N-2 contingency simulation are probabilistically weighted to reflect the actual frequency of occurrence of N-2 contingencies.
- Flexibility 2 (Flex-2)
    - Flex-2-1
        - Amount of LAR in the Valley South System under a complete Valley Substation outage condition (loss of all transformers at Valley Substation) due to a high impact, low probability (HILP) event.
        - Similar to substation events that have occurred previously in the SCE system[57] and more broadly in the industry in which a single catastrophic transformer failure results in damage to an adjacent transformers and associated bus work and other facilities. A similar consequence could occur from an external event such as an earthquake, wildfire, sabotage or electromagnetic pulse (EMP).
        - LAR accumulated over a two-week period that is assumed to occur randomly throughout the year. The two-week recovery period is the minimum expected time to deliver, install, and in-service a remotely stored spare Valley System transformer and to repair associated bus work and other damage.
        - Credits the available system tie-line capacity that can be used to reduce LAR.
    - Flex-2-2
        - Amount of LAR under a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other.
        - The bus work and other substation auxiliary equipment are assumed to remain unaffected, so the Valley Substation spare transformer is assumed to be available to serve load in the Valley South System.

[57] Three SCE AA substations (Vincent, Mira Loma, and El Dorado) have experienced similar events in the past 20 years.

    - The coincident transformer outages are assumed to occur randomly throughout the year and to have a two-week duration – the estimated minimum time to deliver, install, and in-service the remotely-stored spare Valley transformer to restore full transformation capacity to Valley South.
    - Credits the available system tie-line capacity that can be used to reduce EENS.
- <u>Period of Flexibility Deficit (PFD)</u>
  - Maximum number of hours when the available flexibility capacity offered by system tie-lines was less than the required, resulting in LAR.
  - Calculated for N-0 and N-1 contingencies.

6.4. Evaluation of Alternatives Using System Performance Metrics

The alternatives carried forward for quantitative analysis were evaluated using the described system performance metrics and the load forecast described in Section 5. For each metric, the incremental improvement over the baseline No Project Scenario was quantified for each of the project alternatives using the “Effective PV” (mid-range, expected) load forecast. The quantitative evaluation results focus on LAR under N-0 and N-1 contingency conditions and the Flex-1 and Flex-2 metrics. These metrics are most representative of the effective impact on system capacity, reliability and resiliency for each alternative. Other metrics are derived from the calculated LAR values.

The results, compiled in Table 6-1 for the ten -year planning period, present the capacity and reliability/resiliency metrics for the No Project scenario, followed by the equivalent metrics for each of the project alternatives. Where there is a 0, this indicates that the project has completely eliminated the forecasted capacity shortfall (accumulation of LAR under N-0 or N-1 conditions) or reliability/resiliency deficit (accumulation of LAR under the Flex-1, Flex-2-1, or Flex-2-2 scenarios). The results show that none of the project alternatives other than the No Project Scenario result in capacity shortfalls under N-0 contingencies through the 10-year planning period. Additionally, in accordance with SCE Subtransmission Planning Criteria and Guidelines, project scope (impacted line reconductor/rebuild) has been included where necessary for all alternatives to ensure that no LAR is accumulated as a result of N-1 line violations during this period. The ASP provides the greatest overall improvement in both capacity and reliability/resiliency when compared to the No Project scenario. SCE Orange County and SDG&E alternatives also perform well by meeting capacity needs while also providing effective system tie-lines for reliability and resiliency.

Table 6-1 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2028

Alternative	Capacity		Reliability/Resiliency			Capacity Improvement[1]	Reliability/ Resiliency Improvement[1]
	LAR N-0 (MWh)	LAR N-1 (MWh)	Flex-1 (MWh)	Flex-2-1 (MWh)	Flex-2-2 (MWh)		
No Project	250	67	163,415	3,485,449	72,331	-	-
Alberhill System Project	0	0	~~49,088~~30,438	39,532	0	100%	98%
SDG&E	0	0	52,762	466,537	16,573	100%	86%
SCE Orange County[3]	0	13	~~156,480~~ 142,815	437,757	13,523	96%	84%
Menifee	0	0	54,051	~~1204,662~~7 42,386	21,975	100%	~~66~~78%
Mira Loma	0	0	99,638	2,283,812	24,608	100%	35%
Valley South to Valley North[2]	0	0	54,051	3,485,449	21,975	100%	4%
Valley South to Valley North to Vista[2]	0	0	54,051	3,485,449	21,975	100%	4%
Centralized BESS in Valley South	0	0	~~100,979~~ 81,951	3,485,449	72,077	100%	2%
Valley South to Valley North and Distributed BESS in Valley South[2]	0	0	44,298	3,485,449	21,975	100%	5%
SDG&E and Centralized BESS in Valley South	0	0	42,455	466,537	16,573	100%	86%
Mira Loma and Centralized BESS in Valley South	0	0	87,130	2,283,812	24,608	100%	36%
Valley South to Valley North and Centralized BESS in Valley South and Valley North[2]	0	0	64,547	3,485,449	21,975	100%	4%
Valley South to Valley North to Vista and Centralized BESS in Valley South[2]	0	0	64,547	3,485,449	21,975	100%	4%

Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of LAR N-0 and LAR N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Note 3: The 13 MWh of LAR N-1 for SCE Orange County is attributed to bus voltage violations.

Table 6-2 shows the results for the year 2048. Like in 2028, and for the same reasons, ASP, SDG&E and SCE Orange County are the strongest performers. Additionally, the ASP shows the best overall improvement across both capacity and reliability/resiliency metrics. The ASP shows minimal LAR under N-0 and N-1 conditions, due entirely to line violations, which are easily corrected through reconductoring when/as necessary.

Table 6-2 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2048

Alternative	**Capacity**		**Reliability/Resiliency**			**Capacity Improvement**[1]	**Reliability/ Resiliency Improvement**[1]
	LAR N-0 (MWh)	**LAR N-1 (MWh)**	**Flex-1 (MWh)**	**Flex 2-1 (MWh)**	**Flex 2-2 (MWh)**		
No Project	6,310	2,823	526,314	4,060,195	155,780	-	-
Alberhill System Project	3	202	136,664	87,217	~~2,161~~100	99%	95%
SDG&E	244	0	159,201	827,505	51,564	97%	78%
SCE Orange County	232	578	~~491,793~~417,292	777,797	44,419	91%	~~73~~74%
Menifee	114	1,040	163,090	~~1,763,964~~1,207,691	61,787	87%	~~58~~70%
Mira Loma	1,905	1,151	300,643	2,811,049	68,008	67%	33%
Valley South to Valley North[2]	2,680	1,~~040~~041	163,090	4,060,195	61,787	59%	10%
Valley South to Valley North to Vista[2]	852	1,~~040~~041	163,090	4,060,195	61,787	79%	10%
Centralized BESS in Valley South	0	0	~~304,690~~248,058	4,060,195	149,603	100%	~~5~~6%
Valley South to Valley North and Distributed BESS in Valley South[2]	2,564	614	~~133,664~~134,586	4,060,195	61,787	65%	10%
SDG&E and Centralized BESS in Valley South	0	0	128,102	827,505	51,564	100%	79%
Mira Loma and Centralized BESS in Valley South	0	15	262,902	2,811,049	67,834	100%	34%
Valley South to Valley North and Centralized BESS in Valley South and Valley North[2]	0	506	194,760	4,060,195	61,697	94%	9%
Valley South to Valley North to Vista and Centralized BESS in Valley South[2]	735	506	194,760	4,060,195	61,697	86%	9%

Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of EENS N-0 and EENS N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Table 6-3 and Table 6-4 demonstrate the longevity of the alternatives from the perspective of meeting N-0 and N-1 planning criteria. These tables identify the year in which N-0 or N-1 violations occur, and identify which line or transformer causes the violation. These planning criteria violations are referred to as capacity shortfalls. Alternatives which first accrue LAR under N-0 or N-1 conditions after 2028 have no planning criteria violations (and thus do not require system upgrades) within the 10-year planning horizon.

Table 6-3 –Capacity Shortfalls for All Alternatives Through 2048 – N-0 Overloads

Alternative	Year of Overload	Overloaded Element
Alberhill System Project	2046	Alberhill-Fogarty 115 kV Line
SDG&E	2040	**Valley South Transformer**
SCE Orange County	2040	**Valley South Transformer**
Menifee	2043	**Valley South Transformer**
Mira Loma	2031	**Valley South Transformer**
Valley South to Valley North	VN: 2037 VS: 2043	**Valley North Transformer** **Valley South Transformer**
Valley South to Valley North to Vista	VN: 2041 VS: 2043	**Valley North Transformer** **Valley South Transformer**
Centralized BESS in Valley South	None	None
Valley South to Valley North and Distributed BESS in Valley South	VN: 2037	**Valley North Transformer**
SDG&E and Centralized BESS in Valley South	None	None
Mira Loma and Centralized BESS in Valley South	None	None
Valley South to Valley North and Centralized BESS in Valley South and Valley North	None	None
Valley South to Valley North to Vista and Centralized BESS in Valley South	VN: 2041 VS: None	**Valley North Transformer** None
Note: Bolded entries represent capacity shortfalls at the Valley Substation level.		

Table 6-3 demonstrates that all alternatives meet the N-0 planning criteria for the 10-year planning horizon (2028), but some incur N-0 overloads (both line and transformer) well within the 30-year horizon used in the analysis. In practice, these overloads would need to be corrected by SCE through implementation of future projects. For the purpose of this Planning Study, the impacts of these shortfalls are reflected in reduced benefits for the project (or by pairing the alternative with energy storage to create a hybrid alternative).

Table 6-4 –Capacity Shortfalls for All Alternatives – N-1 Overloads

Alternative	First Overload Year[1]	First Overloaded Element	Total Number of Lines Experiencing Criteria Violations (through 2048)
Alberhill System Project	2038	Alberhill-Fogarty 115 kV Line	3
SDG&E	None	None	None
SCE Orange County	2033	Moraga-Pechanga 115 kV Line	4
Menifee	2033	Moraga-Pechanga 115 kV Line	6
Mira Loma	2032	Valley-Newcomb Skylark 115 kV Line	10
Valley South to Valley North	2033	Moraga-Pechanga 115 kV Line	6
Valley South to Valley North to Vista	2033	Moraga-Pechanga 115 kV Line	6
Centralized BESS in Valley South	None	None	None
Valley South to Valley North and Distributed BESS in Valley South	2033	Moraga-Pechanga 115 kV Line	5
SDG&E and Centralized BESS in Valley South	None	None	None
Mira Loma and Centralized BESS in Valley South	2048	Valley-Newcomb-Skylark 115 kV Line	1
Valley South to Valley North and Centralized BESS in Valley South and Valley North	2033	Moraga-Pechanga 115 kV Line	5
Valley South to Valley North to Vista and Centralized BESS in Valley South	2033	Moraga-Pechanga 115 kV Line	5

Note 1: This is the year in which the first line is overloaded during an N-1 condition. For many alternatives, there are additional lines which are overloaded at later dates and contribute to the N-1 LAR value provided in Table 6-2.

Table 6-4 demonstrates that all alternatives meet the N-1 planning criteria for the 10-year planning horizon (2028). However, the majority of alternatives incur N-1 planning criteria violations well before 2048. As in the case of N-0 violations discussed above, SCE would be required to correct these violations through implementation of future projects (typically reconductoring for line violations). For the purpose of this Planning Study, the impact of these violations is reflected in reduced benefits as opposed to individually estimating the cost of mitigation for each violation.[58] The costs and complexity of the individual mitigations are typically not large, nor are the reduced

[58] While individually the scope of these projects to address N-1 line violations is not large, it was not practical in the current study to develop scope and estimates for the large number of line violations across multiple alternatives. The specific projects would typically include reconductoring to address the specific line violations and potentially modification or replacement of structures to accommodate the higher conductor loads.

benefits particularly large when discounted to reflect that they occur later in the time horizon addressed by the analysis. However, the timing and number of line violations and the associated LAR reflecting these 115 kV line violations (shown in Table 6-1 and 6-2) that occur beyond the ten-year planning horizon are both indicative of the relative robustness of each project solution in meeting both near-term and long-term capacity needs.

7.0 Siting and Routing

A siting and routing study was performed on the set of alternatives which were carried forward for quantitative analysis. The siting and routing study identified preferred substation sites and line routes, which were used to assess risk, understand potential environmental impacts, and estimate associated costs for each of the project alternatives. This section describes the approach and methodology used to perform the siting and routing study.

7.1. Opportunities, Concerns, and Constraints Evaluation

Each project alternative requires at least one scope element (e.g., substation, transmission or subtransmission line construction, or energy storage site), with some alternatives sharing scope elements (i.e., the Hybrid Alternatives). For each unique scope element, a discrete study area was created, which defined the geographic area for which the siting and routing study would be performed.

Within each study area, an Opportunities, Concerns, and Constraints (OCC) evaluation was performed by Insignia Environmental[59] in collaboration with SCE to assist in developing initial sites (locations for substations and/or BESS) and route segments (locations for transmission and subtransmission lines):

Opportunity: An opportunity is an area that would provide an advantage to construction and/or operation of the project. Examples are:

- Existing SCE right-of-way
- SCE-owned property
- Previously graded parcels
- Vacant parcels
- Industrial land-use designations

Concern: A concern is an area that could potentially pose a disadvantage to construction and/or operation of the project. Examples are:

- Undisturbed land
- Residential neighborhoods
- Schools
- Tribal land

Constraint: A constraint is an area that should be avoided if at all possible. Examples are:

- Federal property

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[59] Insignia Environmental was contracted by SCE to develop the framework for the OCC evaluation in a web-based GIS mapping tool. Insignia's scope of work included developing initial sites and routes for each alternative, facilitating scoring of sites and routes by SCE SMEs, and performing environmental cost estimating services for preferred sites and routes.

- Areas prone to landslide
- Habitat Conservation Plan Areas
- Areas with sensitive habitats
- Selected airport land-use zones
- Irregular parcel shapes

A geospatial information system (GIS) database was utilized to define opportunities, concerns, and constraints within each study area. Potential sites and route segments were identified within each corresponding study area using an approach that attempted to maximize opportunities while minimizing concerns and constraints. These sites and route segments were added to the GIS database. Initial sites and route segments for each alternative are provided in Appendix C of this Planning Study.

7.2. Scoring of Sites and Segments

SCE Subject Matter Experts (SME) reviewed the GIS database to score the initial sites and route segments using defined siting and routing factors, which are provided in Table 7-1.

Table 7-1 – Siting and Routing Factors

Siting Factors	**Routing Factors**
Civil Engineering	Civil Engineering – Access Roads
Community	Community
Electrical Needs – Distribution	Constructability – Transmission Project Delivery
Information Technology Telecommunications	Electrical Needs – Field Engineering
Land Use	Information Technology Telecommunications
Transmission	Subtransmission / Transmission Design Management
Transmission Telecommunications	
Subtransmission	

Each siting and routing factor contains multiple categories, such as removal of existing structures, permits and restrictions, terrain, accessibility, etc. which are scored based on the SME's review.

The scoring process resulted in a preferred site or preferred route segment for each study area, which were combined as necessary to define each project alternative. The preferred sites and route segments for each alternative are provided in Appendix C of this Planning Study.

8.0 Cost-Benefit Analysis

The project alternatives were evaluated from a cost-benefit standpoint by developing lifecycle costs and monetizing the system performance metrics of each alternative. The project alternatives were then ranked as a function of the benefit-to-cost ratio. The details of the cost-benefit analysis can be found in Quanta Technology Report *Benefit Cost Analysis of Alternatives*.

Note that the cost-benefit analysis differs from a conventional return on investment analysis in that the benefits do not reflect revenues incurred as a result of the investment, but rather they are treated as relative estimates of avoided costs that would be incurred by SCE customers if the investments were not made. Care was taken to apply a consistent approach across alternatives in terms of development of costs as well as in the approach for determination and monetization of the benefits (avoided customer costs). Accordingly, more attention should be paid to the relative performance of alternatives than to the absolute values of accrued benefits and associated benefit-to-cost ratios.

8.1. Methodology

8.1.1. Costs

The lifecycle costs of each project alternative were calculated, including upfront and future capital costs, as well as recurring operations and maintenance (O&M) costs. Project costs were spread out across likely project implementation (design, procurement and construction) durations, ranging from 2 to 5 years, depending on project scope and complexity. These costs were then discounted to the present using the PVRR[60] method consistent with SCE practice when determining total present-value cost for capital projects.

The cost estimating approach used for each project element is summarized in Table 8-1.

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[60] PVRR is a single calculated value that sums the time-discounted cash flows of the project (in terms of revenue requirements) for each year of the project.

Table 8-1 – Cost Estimating Approach Summary

Project Element	Estimate Approach
Licensing	• Past ASP licensing costs applied to all projects, with additional costs accruing at the same rate as ASP for an additional 2 years for ASP and 4 years for other alternatives to account for CEQA activities.
Substation	• Developed engineering scoping checklists to identify major scope elements (switchracks, transformers, circuit breakers, disconnect switches, foundations, civil work, etc.). • SCE cost estimating SMEs created cost estimates based on scoping checklists.
Corporate Security	• Based on past SCE projects of similar scope.
Bulk Transmission and Subtransmission	• Identified length of routes, line type (single-circuit, double-circuit, overhead, underground) and terrain. • Applied a combination of CAISO and SCE Unit Costs.
Transmission Telecommunications	• Identified length of fiber optic line based on preferred routes. • Applied a combination of CAISO and SCE Unit Costs.
Distribution	• Review of impact to existing distribution circuits along preferred routes to identify likely scope. • Applied SCE Unit Costs based on recent project bids.
IT Telecom	• Included for Substation and BESS sites, and alternatives with line protection upgrades. • Applied a combination of CAISO and SCE Unit Costs.
Real Properties	• Bottom-up cost estimate utilizing siting and routing information to identify required parcels and ROWs.
Environmental[61]	• Bottom-up cost estimate incorporating local planning and permit development and execution (surveying, mitigation, monitoring) support.
BESS	• Based on industry data to include inverter, battery, balance of plant and contractor turnkey costs. • Sized to meet N-0 transformer capacity shortfalls for 30 years. • Sizes are augmented to account for degradation
Owner's Agent	• 10% of above costs for owner's agent costs.
Uncertainty	• Scored impact and probability of various uncertainty categories using 3x3 matrix (low, medium, high). See Appendix D for uncertainty scoring matrix.

The siting and routing study was heavily relied upon to inform cost estimates for each alternative, since a significant portion of project costs rely on the specific substation/BESS site locations and the routes for subtransmission and transmission lines to implement the alternatives. For line construction, cost per mile was estimated by considering the number of poles per mile and the amount of conductor/cable per mile, while incorporating the potential topology, climate, and population density for the line route into the construction cost estimate. For new substations and additions to existing substations, costs were estimated using known costs of substation equipment while also incorporating earthwork and new construction costs. As described in Table 8-1, real properties costs were accounted for as necessary for all alternatives using preferred siting and routing information. O&M costs for non-BESS project scope were set at 1.5% of capital

[61] Environmental cost estimating was performed by Insignia Environmental.

expenditures for equipment related costs (i.e., substation, transmission, subtransmission, etc.), escalated at 2.5% each year based on industry experience.

For alternatives that included BESS, both centralized and distributed, costs were estimated using typical $/kWh and $/kW system costs for the base system purchase. O&M costs were estimated by considering a 1.3% and 1.7% ongoing expenditure, using the total kW-cost and kWh-cost of the system, respectively, as the basis.[62] For all BESS alternatives, batteries are assumed to be installed incrementally, rather than all at once, the price of which is discounted over time according to an assumed cost-change factor. The total cost of the system includes periodic augmentation of installed batteries, to account for capacity degradation, as the age of each installed BESS nears end of life[63], as well as inverter replacements every 10 years.

Electricity wholesale market revenue was considered by allowing the BESS to participate in capacity or regulation markets, except during the months of June, July, August, and September, when electrical load in the region is projected to be highest. The time of year was restricted to ensure required availability of the BESS for the reliability function – the BESS must be available to serve peak load at various times throughout the year. Revenue from market participation activities was accounted for on a yearly basis and discounted back to the present using a 10% discount factor. The present value of market revenue was then used to offset the total project cost.

Uncertainty costs were also incorporated into the cost estimate to account for the relative complexity and extent of detailed project development, environmental analysis and design for each alternative. Uncertainty costs are intended to reflect costs comprising a combination of risk and contingency.

A matrix consisting of various general, transmission, subtransmission, substation and battery project uncertainties was developed in order to quantify challenges typically encountered during project planning and execution which add delay and costs, such as public opposition, permitting or agency delay, and required undergrounding. The preferred sites and routes of each alternative were reviewed by SCE subject matter experts to determine the extent that the uncertainty categories would apply. A total uncertainty score based on the likelihood and impact of each uncertainty category was developed for each alternative and the ASP, which served as a basis because of the maturity of its environmental, licensing, and engineering design relative to the other alternatives.

The uncertainty score of each alternative was translated to an uncertainty cost as a percentage of total project costs. The lower bound of the uncertainty costs was based on the ASP uncertainty score and ratio of the known ASP risk and contingency costs, and the upper bound of the uncertainty costs was capped at 50%, which is consistent with AACE Level 3/4 cost estimate accuracy, so as to limit the impact of risk/uncertainty on the cost-benefit analysis results. However, SCE's experience is that project costs for projects that have not been through the complete process of development, design, licensing and stakeholder engagement can change by more than 50%

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[62] For BESS cost-estimates, several publically available sources of BESS cost information were consulted, including sources from Lazard, Greentech Media, and Pacific Northwest National Laboratory.

[63] See Balducci, et al, PNNL-28866, "Energy Storage Technology and Cost Characterization Report", July 2019.

when advancing to the execution stage. The risks of higher costs due to these various sources of uncertainty are therefore addressed on a qualitative basis in Section 9.0.

Uncertainty scores and costs, as a percentage of total capital expenditures, are provided for each alternative in Table 8-2. Generally the highest uncertainty scores are associated with projects with the longest or most challenging line routes. Additionally, projects that have a combination of lines, substations and BESS sites, and thus include risks associated with each project element, have uncertainty scores approaching the higher end of the range. While overall the BESS project element has lower uncertainty contribution than substations or lines, the Valley South to Valley North and Distributed BESS in Valley South alternative has lower uncertainty than the Centralized BESS alternatives because it is assumed that development inside existing SCE distribution substation fence lines has less overall licensing, siting and execution risk than developing a new larger centralized BESS site. Complete scoring details are provided in Appendix D.

Table 8-2 – Uncertainty Scores and Costs for All Alternatives

Alternative	Uncertainty Score	Uncertainty Costs (% of Capital Expenditures)
Alberhill System Project	153	26%
SDG&E	287	48%
SCE Orange County	275	46%
Menifee	244	41%
Mira Loma	264	44%
Valley South to Valley North	188	32%
Valley South to Valley North to Vista	198	33%
Centralized BESS in Valley South	181	31%
Valley South to Valley North and Distributed BESS in Valley South	177	30%
SDG&E and Centralized BESS in Valley South	300	50%
Mira Loma and Centralized BESS in Valley South	277	46%
Valley South to Valley North and Centralized BESS in Valley South and Valley North	249	42%
Valley South to Valley North to Vista and Centralized BESS in Valley South	265	44%

Table 8-3 shows the cost estimates for all alternatives. The alternatives are ranked in terms of PVRR, and the total cost in nominal dollars is included for context. The alternatives that merely transfer load from one system to another are the lowest in total cost, while the Conventional and Hybrid Alternatives that require new substation construction rank highest. Alternatives incorporating BESS become particularly expensive when the BESS is required to meet longer duration capacity shortfalls, thus requiring large scale battery additions.

Table 8-3 – Costs, Ranked Lowest to Highest by PVRR for All Alternatives

Alternative	Total Nominal Capital Cost ($M)	PVRR ($M)
Valley South to Valley North	$221	$207
Valley South to Valley North and Distributed BESS in Valley South	$326	$232
Valley South to Valley North to Vista and Centralized BESS in Valley South	$505	$289
Valley South to Valley North to Vista	$317	$290
Mira Loma	$365	$309
Menifee	$396	$331
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$1,172	$367
SDG&E	$540	$453
Alberhill System Project	$545	$474
Centralized BESS in Valley South	$1,474	$525
SDG&E and Centralized BESS in Valley South	$923	$531
Mira Loma and Centralized BESS in Valley South	$1,396	$560
SCE Orange County	$951	$748

8.1.2. Benefits

Four main LAR benefit categories were selected for monetization: LAR under N-0 conditions; LAR under N-1 conditions; Flex-1; and Flex-2.[64] These metrics most accurately reflect the reliability and resiliency benefit of the alternatives to SCE customers, most readily differentiate among the alternatives, and are not duplicative of each other and thus can be combined to reflect the overall benefit of alternatives. Additionally, the analysis monetized the reduction in System Losses achieved by each alternative, although this metric was not a significant differentiator among alternatives in the cost-benefit analysis.

In monetizing these benefits, the metrics are first adjusted by assigning probabilities for the line or transformer outages that are associated with each metric. Line outage probabilities were calculated from historical data (2005 – 2018) for the Valley North and South Systems in order to have a large enough sample of outages to support the statistical analysis. Outage probabilities were calculated for single contingency (N-1) events to monetize the LAR (N-1) metric and for double-circuit contingency (N-2) events for the Flex-1 metric. The aggregate line outage probability for the entire Valley System is then applied to each line or combination of lines in Valley South on a per line-mile basis. N-1-1 outages were not included in the Flex-1 monetization because the probability of independent, coincidental outages occurring during system load conditions in which loss of service to customers would occur is extremely low relative to N-1 contingencies. Note that this simplification somewhat understates the value of system tie-lines. System tie-lines are

[64] The analysis also includes system losses as a monetized benefit metric. They are not a focus of the alternatives analysis in either the quantitative metrics assessment or the cost-benefit analysis, as a reduction in losses typically represents a small fraction of the overall benefits that a project provides.

commonly used to either proactively or reactively limit the impact of potential N-1-1 outages that might otherwise occur when lines are out of service for extended periods of time for planned maintenance or construction. In cases where tie-lines are not available, where practical, these construction or maintenance activities will be limited to times of the year when system loading conditions will not result in loss of service to customers should an additional (unplanned) line outage occur at the same time as the planned outage. The value of this flexibility is not captured in this analysis. Based on the historical Valley South and Valley North outage data, the mean line outage durations were calculated to be 2.8 hours (LAR N-1) and 3.0 hours (Flex-1).

Transformer outage probabilities were based on a postulated 1-in-100 year event for Flex-2-1 and based on an industry survey and statistical analysis of major (greater than 7 day) transformer failures for Flex-2-2[65]. The Flex-2-2 scenario assumes that one of the two normally load-serving transformers of the Valley South System experiences a catastrophic fire or explosion that causes collateral damage to the adjacent transformer. The spare transformer, which is not located within the immediate vicinity of the two load-serving transformers, is unaffected and is assumed to be aligned to the undamaged, Valley South 115 kV bus.

Transformer outages associated with both the Flex-2-1 and Flex-2-2 metrics were assumed to be two weeks, which is representative of the minimum restoration time for a high impact low probability (HILP) event resulting in a complete loss of Valley Substation. This assumption likely understates the likely duration of a Flex-2 type event considering that similar events at SCE have taken months to repair as a result of the collateral damage to structures, bus work, control cables and other auxiliaries. This, most-optimistic, duration was assumed so that a singular metric would not dominate the cost benefit analysis results

These probability adjusted metrics were then monetized using cost of service interruption data from the SCE Value of Service study (as presented in the SCE General Rate Case[66]). The primary objective of the Value of Service study is to estimate outage costs for various customer classes, using the well-established theoretical concept of "value-based reliability planning." This concept has been used in the utility industry for the past 30 years to measure the economic value of service reliability. The estimation of outage costs differs for customer classes: commercial outage costs are based on a direct-cost measurement, since these costs are easily measured, whereas residential outage costs are based on a willingness-to-pay survey (customer perception or estimation of costs rather than a detailed buildup). The study presents equivalent costs of unserved demand (kW) and load (kWh) from the perspective of commercial and residential customers. As discussed earlier, the absolute value of the cost of service interruption is not critical as the same values are applied to all alternatives.

Figure 8-1, which is derived from the SCE Value of Service (VoS) study, provides the cost of unserved load for outages of various durations. This figure shows that the initial hour of

[65] See CIGRE Reference 642, Transformer Reliability Survey, December 2015.

[66] See WP SCE-02, Vol. 4, Pt. 1, Ch. II – Book A – pp. 12 – 109 – Southern California Edison: 2019 Value of Service Study.

interruption is deemed most costly on a $/kWh basis for both customer classes declining through the 4th hour then stabilizing.

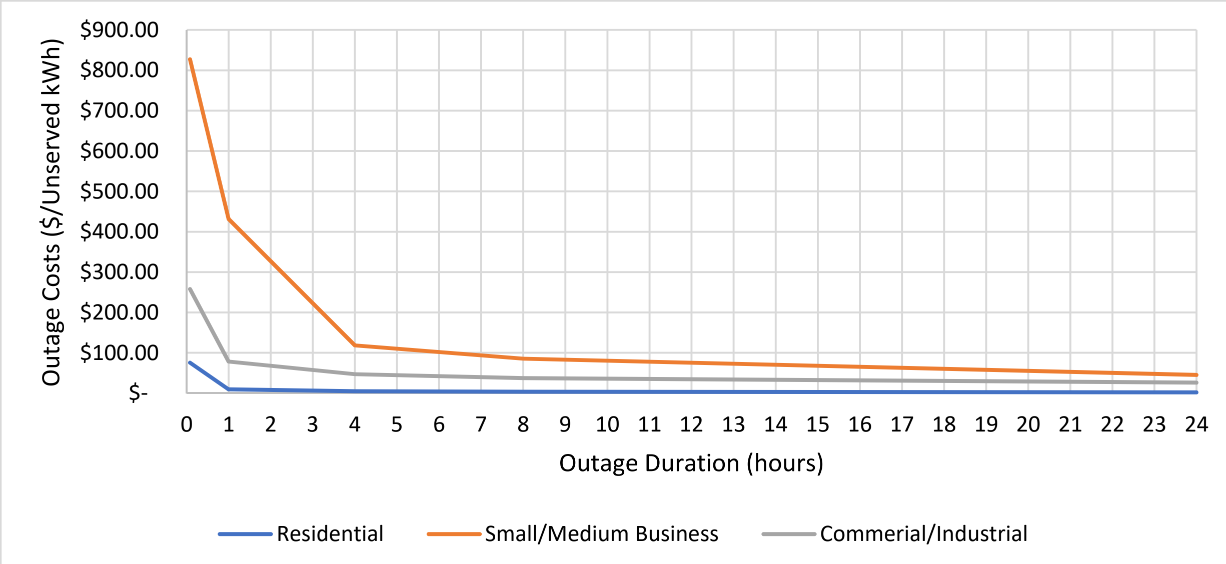

Figure 8-1 – Customer Outage Costs

It is SCE's practice to minimize the impact of an extended outage to any single customer by periodically rolling the outages within the system. Accordingly, in applying the VoS study to the LAR (N-0), LAR (N-1), Flex-1 and Flex-2-2 metrics, the one hour outage monetization rate in the VoS study is applied for each hour of the period where load would be unserved. For the Flex 2-1 metrics the average of the one hour and 24 hour monetization rates is used because in that associated outage scenario load cannot be rolled. The average of the two rates is applied to recognize that outages lasting substantially longer than 24 hours have impacts not reflected in the VoS study 24 hour rate, such as property damage, relocation, and other direct costs. Based on data reported in the VoS study, a mix of 33% residential, 36% small/medium business and 31% commercial and industrial customer load was used to monetize the annual, probability-weighted LAR values for each of the metrics (1 hour costs for LAR N-0, LAR N-1, Flex-1 and Flex-2-2, average of 1 hour and 24 hour costs for Flex-2-2). The customer class load percentages and costs per kWh are provided in Table 8-4.

Table 8-4 –Value of Service by Customer Class

Customer Class	Load %	$/kWh (1 hour)	$/kWh (Flex-2-1)
Residential	33%	$9.47	$5.68
Small/Medium Business	36%	$431.60	$238.41
Commercial & Industrial	31%	$78.28	$52.11

Table 8-5 ranks the total monetized project benefits for each project from highest to lowest. As was the case for the benefits (before monetization) described above, the alternatives that directly address the capacity need through the construction of adequate substation transformation capacity, such as the ASP, SDG&E, and SCE Orange County alternatives, and directly address the reliability/resiliency need through the creation of system tie-lines provide the greatest overall monetized benefits. These alternatives provide a means to initially transfer a large amount of load away from the Valley South System, thus increasing the operating margin of the Valley South System transformers and extending the timeline for when the transformers would again be at risk of becoming overloaded. In addition, the effectiveness of the system tie-lines created in these alternatives is maximized, since the new substations (with substantial transformation capacity) do not constrain the amount of additional load that can be transferred during planned or unplanned contingencies. Among these alternatives, the ASP would provide the greatest benefits, largely because of its location from the perspective of electrical system performance, and maximizes the effectiveness of system tie-lines.

Like the ASP alternative, the Menifee alternative creates a new 500 kV to 115 kV bulk power system supplied substation and thus is robust in meeting capacity needs. However, it is not as effective in addressing reliability and resiliency contingency events. This is because the system tie-lines created by this alternative do not allow for the additional transferring of load from the Valley South System to the Valley North System. The tie-lines do allow for transfer of load back to Valley South from the new Menifee system if there were to be a reliability/resiliency need in that system; thus the tie-lines do benefit the relatively small number of customers that were initially transferred to the new Menifee system.

Hybrid alternatives that use BESS to address long-term capacity shortfalls, along with system tie-lines, provide a higher level of overall benefits relative to the associated baseline, conventional scope (e.g., the SDG&E and Centralized BESS in Valley South alternative accrues higher benefits than SDG&E, due to the improved performance of the LAR N-0 metric, while alternatives that transfer load from one existing system to another, such as the Valley South to Valley North and Valley South to Valley North to Vista alternatives, provide the least overall benefit among the alternatives. These load-transfer alternatives actually perform well in improving short-term capacity, but do not significantly improve reliability/resiliency between the systems (through construction of new subtransmission lines to transfer load away from the Valley South System) on a permanent basis, as opposed to the intended, temporary use of system tie-line capacity for operational flexibility. In these cases, no additional load can be transferred during planned or unplanned contingencies in Valley South; however, load can be transferred back to Valley South from Valley North if there is a problem in the Valley North system. This transfer capability is of limited value to the Valley North system because Valley North already has multiple effective system tie-lines.

Centralized BESS ranks at the lower tier of alternatives despite satisfying the transformation capacity need and addressing additional line violations over the 30 -year analysis period. However, the Centralized BESS alternative realizes only a very small amount of the reliability/resiliency benefits because it does not include system tie -lines which are needed to address longer duration events such as a catastrophic failure affecting multiple transformers at Valley and to address line outages that can be localized and also have extended duration.

Table 8-5 – Monetized Benefits, Ranked Highest to Lowest for All Alternatives

Alternative	Benefit($M)
Alberhill System Project	$4,282
SDG&E and Centralized BESS in Valley South	$4,041
SCE Orange County	$4,021
SDG&E	$4,001
Menifee	$~~3,648~~3,882
Mira Loma and Centralized BESS in Valley South	$3,132
Mira Loma	$2,601
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$2,542
Centralized BESS in Valley South	$2,535
Valley South to Valley North to Vista and Centralized BESS in Valley South	$~~2,468~~2,479
Valley South to Valley North to Vista	$2,470
Valley South to Valley North and Distributed BESS in Valley South	$2,165
Valley South to Valley North	$2,156

8.1.3. Load Forecast Uncertainty

As discussed in Section 5.4, uncertainty in the 30 -year load forecast was evaluated by considering three distinct approaches for incorporating DER growth. These forecasts were then used to perform cost-benefit sensitivity analyses for all the alternatives. The methodology for determining the costs and benefits for these cost-benefit sensitivity analyses is identical to the methodology just described.

8.2. Results

8.2.1. Cost-Benefit Analysis - Ratio

Table 8-6 shows the results of comparing benefits to costs for all of the project alternatives, grouped by the alternatives that meet project objectives and those that do not. The benefit-cost ratio computes the monetized benefits discounted to the present divided by the PVRR costs.

Table 8-6 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$4,282	9.0	Yes
SDG&E	$453	$4,001	8.8	Yes
Mira Loma	$309	$2,601	8.4	Yes
SDG&E and Centralized BESS in Valley South	$531	$4,041	7.6	Yes
Mira Loma and Centralized BESS in Valley South	$560	$3,132	5.6	Yes
SCE Orange County	$748	$4,021	5.4	Yes
Menifee	$331	$~~3,648~~3,882	11.~~0~~7	No
Valley South to Valley North	$207	$2,156	10.4	No
Valley South to Valley North and Distributed BESS in Valley South	$232	$2,165	9.3	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	$~~2,468~~2,479	8.~~5~~6	No
Valley South to Valley North to Vista	$290	$2,470	8.5	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	$2,542	6.9	No
Centralized BESS in Valley South	$525	$2,535	4.8	No

The performance of the three alternatives that perform best in the overall cost-benefit analysis (Menifee, Valley South and Valley North, and Valley South to Valley North and Distributed BESS in Valley South) is driven principally by their lower cost. These alternatives however do not meet the project objective of having system tie-lines that are effective in transferring additional load out of Valley South in the event of line or transformer outages in the Valley South System that result in a need for this flexibility to be able to serve load. In all of these alternatives, the system tie-lines that are created allow a limited transfer of load back into Valley South from the adjacent (Menifee or Valley North) system. This capability benefits the relatively small number of customers that are served by the substations transferred out of Valley South in implementing the project alternative but the customers remaining in the Valley South System continue to have no useful system tie-lines to address their reliability/resiliency needs. Creating effective system tie-lines for these alternatives is not practical because additional distribution substations would need to be transferred to make the system tie-lines effective. Distribution substations nearest Valley Substation (and thus sufficiently accessible to be included in the alternative) are also substations through which power coming from the Valley South System transformers is routed before continuing on a path to serve the remaining distribution substations to the south. Transferring these substations, without significant additional 115 kV subtransmission line construction to effectively bypass them, would disrupt the design of the electrical network and adversely impact the ability to serve the more distant substations in the Valley South System.

Among the alternatives that meet project objectives, ASP, SDG&E, and Mira Loma are included in the top tier of alternatives, with ASP ranking highest. Both ASP and SDG&E rank high primarily due to their high benefits. These alternatives provide long-term N-0 transformer capacity margin and have effective system tie-lines. The SDG&E alternative satisfies the capacity need through 2040 while ASP meets the need beyond 2048. The benefit-to-cost ratio of the Mira Loma alternative is similar to SDG&E and ASP; however, in this case the cost/benefit performance is driven by low costs and moderate benefit levels. The Mira Loma alternative is a short term capacity solution, as it does not meet capacity needs beyond 2031 as a standalone alternative. This is the shortest term capacity solution among of all the alternatives. In as soon as 2031, another project or NWA solution would need to be implemented to address the transformer capacity N-0 contingency violations associated with this shortfall. These incremental capacity additions are reflected in the Mira Loma and Centralized BESS in Valley South Alternative and result in an alternative that is ranked much lower in the overall benefit-to-cost ratio (number 5 of 6 for alternatives that meet project objectives and among the lowest overall).

8.2.2. Cost-Benefit Analysis - Incremental

When there are large differences in costs and benefits among alternatives, as in the analysis reported here, it is appropriate to consider the incremental benefit that is obtained for an increased investment relative to a lower cost alternative. This approach formalizes and quantifies the decisions made every day by consumers when they decide whether buying a higher priced product that comes with additional benefits is "worth it". The approach used for this incremental cost - benefit analysis is described below.

The incremental cost-benefit analysis ranks the projects from lowest to highest in PVRR cost. The analysis begins by considering the lowest cost project and comparing the benefits of the project to the cost of the project. If the benefits are greater than the costs, that is, the benefits outweigh the costs, then the project is deemed viable and chosen as the baseline. The next highest-cost project is then considered. The incremental benefits of the second project are compared to the incremental, or additional, cost of the second project. If the incremental benefits of the second project are greater than the incremental cost of the second project, this second project is deemed viable and becomes the new baseline.

It is possible that the next highest-cost project in the list provides fewer benefits than the previous baseline project. The incremental benefits would be negative, i.e., the project under consideration provides even fewer overall benefits than the current baseline project. In this case, the benefit-to-cost ratio is negative, and the project is not deemed viable. Similarly, a project may provide positive incremental benefits, but the incremental cost of the project may be greater than the incremental benefits provided. In this case, the benefit-to-cost ratio is <1, and the project is not deemed viable. In either of these cases, the project under consideration is rejected, and the next highest-cost project in the list is considered. This process is repeated, moving though the list in order of lowest to highest cost, until no other alternative can provide incremental benefits that exceed the incremental cost. Table 8-7 shows the results of the incremental cost-benefit analysis.

Table 8-7 – Incremental Cost-Benefit Analysis Results for All Alternatives

Alternative	PVRR Cost ($M)	Cost Ranking (least to greatest)	Cost Ranking Comparison	Δ Benefits / Δ Costs	Incremental Benefits > Costs?
Valley South to Valley North	$207	1	-	-	-
Valley South to Valley North and Distributed BESS in Valley South	$232	2	1 vs 2	0.~~38~~36	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	3	1 vs 3	3.~~8~~9	Yes
Valley South to Valley North to Vista	$290	4	3 vs 4	~~2.2~~-9.0	~~Yes~~No
Mira Loma	$309	5	~~4~~ 3 vs 5	~~7.0~~6.1	Yes
Menifee	$331	6	5 vs 6	~~47.6~~58.2	Yes
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	7	6 vs 7	-~~30.8~~37.2	No
SDG&E	$453	8	6 vs 8	~~2.9~~0.98	~~Yes~~No
Alberhill System Project	$474	9	~~8~~ 6 vs 9	~~13.4~~2.8	Yes
Centralized BESS in Valley South	$525	10	9 vs 10	-34.3	No
SDG&E and Centralized BESS in Valley South	$531	11	9 vs 11	-4.2	No
Mira Loma and Centralized BESS in Valley South	$560	12	9 vs 12	-13.4	No
SCE Orange County	$748	13	9 vs 13	-1.0	No

The analysis begins with the lowest cost project, Valley South to Valley North. Moving through the list from lowest to highest cost (identified in the column titled Cost Ranking with 1 being least cost and 13 being greatest cost), the next project is Valley South to Valley North with Distributed BESS in Valley South. The incremental benefits in moving from Valley South to Valley North, to Valley South to Valley North and Distributed BESS in Valley South do not exceed the incremental costs; as such, the Valley South to Valley North alternative remains the baseline alternative for the next highest cost alternative. This process is repeated until the final alternative which provides an incremental benefit-to-cost ratio greater than 1 is identified. The ASP provides substantial incremental benefits over the incremental cost (~~13.4~~2.8) compared to ~~SDG&E~~Menifee. Thus, the results show that the higher benefits of ASP are cost effective.

8.3. Load Forecast Uncertainty

SCE recognizes there is additional potential option value in alternatives with less expensive upfront costs that meet system needs for a shorter timeframe over alternatives with higher upfront costs but longer -term system benefits. Specifically, should load develop slower than forecasted, the alternatives with lower front -end costs would incur future costs later than currently modeled, thus favorably affecting their cost-benefit performance. An analysis was performed to evaluate the sensitivity of the cost-benefit analysis results to uncertainty in the 30-year load forecast.

8.3.1. Spatial Load Forecast – Lower

Table 8-8 shows the results of comparing costs to benefits for all project alternatives, given the lower (Spatial PVWatts) forecast. As discussed in Section 5.4, the Spatial PVWatts forecast represents a lower load forecast reflecting higher rates of on-peak PV or other load reducing DERs. It represents a nominal average annual load growth rate of 0.6% compared to the 0.8% rate reflected in the base (Dependable PV) forecast. Due to the lower forecasted load, fewer benefits are accrued for all the alternatives, thus lowering the benefit/cost ratios. Costs for all alternatives that include BESS are also reduced due to the reduced quantity of batteries required to meet system N-0 capacity needs, resulting in the benefit-to-cost ratios of the alternatives being more closely grouped. However, the reduced load forecast does not significantly affect the relative performance of the highest ranked alternatives. The highest ranked alternatives are still Menifee, ASP, SDG&E, and SDG&E and Centralized BESS in Valley South. The relative performance of the Mira Loma alternative does drop somewhat due to the reduced value of meeting capacity needs relative to the Flex 2-1 metric in the low load forecast scenario. The ASP continues to have the best incremental cost benefit analysis performance with an incremental benefit to cost ratio of 10.5 relative to the next best performing alternative (SDG&E).

Table 8-8 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Lower Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$2,740	5.78	Yes
SDG&E	$453	$2,520	5.56	Yes
SDG&E and Centralized BESS in Valley South	$479	$2,520	5.26	Yes
Mira Loma	$309	$1,~~511~~512	4.89	Yes
Mira Loma and Centralized BESS in Valley South	$448	$1,625	3.63	Yes
SCE Orange County	$748	$2,533	3.39	Yes
Menifee	$331	$2,381	7.19	No
Valley South to Valley North and Distributed BESS in Valley South	$200	$955	4.77	No
Valley South to Valley North	$207	$955	4.61	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$255	$1,039	4.08	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$269	$1,036	3.85	No
Valley South to Valley North to Vista	$290	$1,036	3.57	No
Centralized BESS in Valley South	$381	$1,032	2.71	No

8.3.2. Spatial Load Forecast – Higher

Table 8-9 shows the results of comparing costs to benefits for all project alternatives, given the higher (Spatial Base) forecast. The Spatial Base forecast assumes continuation of current trends in PV and other DER adoption and thus is reflective of a future scenario where increased electrification effectively offsets increases in DER adoption. The result is an average annual load growth rate of 1.0% compared to 0.8% in the base (Spatial Effective PV) forecast.

The relative performance of alternatives with capacity margin improves in this scenario and additional reliability/resiliency benefits also accrue due to the increasing load at risk. The overall benefits and benefit-to-cost ratios increase substantially overall, but the overall benefit-to-cost ratio rankings of alternatives does not substantially change. The incremental benefit-to-cost ratio advantage of ASP increases substantially relative to Menifee (the second best performing alternative), with an incremental benefit-to-cost ratio of 4.1. This is because the ASP has substantial capacity margin to address higher load growth and the reliability/resiliency benefits associated with its system tie lines are amplified due to the increased load at risk. The relative performance of alternatives with heavy reliance on BESS is adversely affected under this scenario due to increasing battery costs.

Table 8-9 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Higher Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$7,788~~9~~	16.4	Yes
SDG&E	$453	$7,218~~9~~	15.9	Yes
Mira Loma	$309	$4,766~~5~~	15.4	Yes
SDG&E and Centralized BESS in Valley South	$658	$7,523~~4~~	11.4	Yes
Mira Loma and Centralized BESS in Valley South	$601	$6,604~~5~~	11.0	Yes
SCE Orange County	$748	$7,258~~9~~	9.7	Yes
Menifee	$331	$7,201~~2~~	21.8	No
Valley South to Valley North to Vista	$290	$4,617~~8~~	15.9	No
Valley South to Valley North	$207	$2,618	12.7	No
Valley South to Valley North and Distributed BESS in Valley South	$228	$2,736~~8~~	12.0	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$404	$4,771~~2~~	11.8	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$700	$6,016~~8~~	8.6	No
Centralized BESS in Valley South	$848	$6,008~~9~~	7.1	No

8.4. Battery Cost Sensitivity

Cost estimates for BESS are based on current industry data and include battery, inverter, balance of plant, and engineering, procurement, and construction costs, and reflect future price reductions anticipated by industry analysts. The lower upfront-cost alternatives with BESS could potentially benefit from lower -than -expected future costs through improvements in technology or market conditions. A sensitivity analysis was performed with BESS costs reduced by 50% to quantify this scenario.

Table 8-10 shows the results of the benefit-to-cost comparison for the lower (Spatial PVWatts) forecast. The alternatives with BESS are shown in red for emphasis.

Table 8-10 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Reduced Battery Costs and Low Load Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$2,740	5.8	Yes
SDG&E	$453	$2,520	5.6	Yes
SDG&E and Centralized BESS in Valley South	$463	$2,520	5.4	Yes
Mira Loma	$309	$1,~~511~~512	4.9	Yes
Mira Loma and Centralized BESS in Valley South	$363	$1,625	4.5	Yes
SCE Orange County	$748	$2,533	3.4	Yes
Menifee	$331	$2,381	7.2	No
Valley South to Valley North and Distributed BESS in Valley South	$200	$955	4.8	No
Valley South to Valley North	$205	$955	4.7	No
Centralized BESS in Valley South	$252	$1,032	4.1	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$255	$1,039	4.1	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$269	$1,036	3.9	No
Valley South to Valley North to Vista	$309	$1,036	3.4	No

The benefit-to-cost ratios for alternatives without BESS remain unchanged, but as anticipated, the alternatives with BESS improve in ranking. The Centralized BESS in the Valley South alternative has a significant improvement in benefit-to-cost ratio under this scenario. This is because this alternative relies solely on BESS to meet capacity needs in the Valley South System and therefore benefits the most from a reduction in BESS costs. The remaining alternatives with BESS improve as well but their lower benefits prevent significant improvement in benefit-to-cost ranking. Conventional alternatives such as Menifee, SDG&E and the ASP continue to rank high under this scenario. The incremental benefit-to-cost ratio advantage of ASP is unchanged because neither ASP nor SDG&E include BESS and they remain the two top ranked alternatives.

Table 8-11 shows the results of the benefit -to -cost comparison for the middle (Spatial Effective PV) forecast.

Table 8-11 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Reduced Battery Costs and Base Case Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$4,282	9.0	Yes
SDG&E	$453	$4,001	8.8	Yes
SDG&E and Centralized BESS in Valley South	$475	$4,041	8.5	Yes
Mira Loma	$309	$2,601	8.4	Yes
Mira Loma and Centralized BESS in Valley South	$439	$3,132	7.1	Yes
SCE Orange County	$748	$4,021	5.4	Yes
Menifee	$331	$3,~~648~~882	11.~~0~~7	No
Valley South to Valley North and Distributed BESS in Valley South	$203	$2,165	10.7	No
Valley South to Valley North	$207	$2,156	10.4	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$260	$2,~~468~~479	9.5	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$272	$2,542	9.3	No
Valley South to Valley North to Vista	$290	$2,470	8.5	No
Centralized BESS in Valley South	$345	$2,535	7.4	No

As with the lower forecast, the alternatives with BESS improve in benefit -to -cost ranking under the base case (middle) load forecast scenario when BESS costs are halved. However, the reduction in BESS costs coupled with the lower benefits of the BESS alternatives in general does not change the relative ranking. An exception is the SDG&E and Centralized BESS which now performs slightly better than Mira Loma in overall benefit -to -cost ratio. The incremental benefit-to-cost ratio advantage of ASP is unchanged because neither ASP nor ~~SDG&E~~Menifee include BESS and they remain the two top ranked alternatives in the baseline incremental cost/benefit analysis.

Table 8-12 shows the results of the benefit -to -cost comparison for the high (Spatial Base) forecast.

Table 8-12 – Costs, Benefits, and Benefit-Cost Ratio for All Alternatives – Reduced Battery Costs and High Forecast

Alternative	PVRR ($M)	Benefit ($M)	Benefit-Cost Ratio	Meets Project Objectives?
Alberhill System Project	$474	$7,~~789~~788	16.4	Yes
SDG&E	$453	$7,218~~9~~	15.9	Yes
Mira Loma	$309	$4,766~~5~~	15.4	Yes
Mira Loma and Centralized BESS in Valley South	$446	$6,604~~5~~	14.8	Yes
SDG&E and Centralized BESS in Valley South	$537	$7,523~~4~~	14.0	Yes
SCE Orange County	$748	$7,258~~9~~	9.7	Yes
Menifee	$331	$7,201~~2~~	21.8	No
Valley South to Valley North to Vista	$290	$4,617~~8~~	15.9	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	$317	$4,771~~2~~	15.1	No
Valley South to Valley North and Distributed BESS in Valley South	$195	$2,736~~8~~	14.~~1~~0	No
Valley South to Valley North	$207	$2,618	12.7	No
Valley South to Valley North and Centralized BESS in Valley South and Valley North	$486	$6,016~~8~~	12.4	No
Centralized BESS in Valley South	$538	$6,008~~9~~	11.2	No

Again, the results are substantially unchanged for the high load forecast scenario with 50% lower BESS costs. The superior incremental benefit-to-cost ratio of ASP is unaffected, as the ASP still has a 4.1 incremental benefit-to-cost ratio over the Menifee alternative.

8.5. Overall Sensitivity Analysis Results

The sensitivity analysis demonstrates that for reasonable downward adjustments in load forecast uncertainty and BESS costs, the option value of deferring capital investments needed to meet system requirements is not substantial. Overall, the substation solutions including the ASP have superior incremental benefit -to -cost ratios indicating that the significant capacity they add to the Valley South System and the multiple, useful system tie-lines are cost effective. Further, the analysis demonstrates that the conventional substation alternatives are more robust from the perspective of addressing future load growth uncertainties than other alternatives, providing margin for higher future load growth scenarios beyond those considered in this analysis.

9.0 Risk Assessment

This section of the Planning Study addresses risks of various alternatives that are not readily quantifiable in the context of the cost-benefit analysis.

9.1. Wildfire Mitigation Efforts and Associated Impacts on Alternatives

Minimizing wildfire risk is a critical consideration for SCE throughout the enterprise, including in project planning. Each of the project alternatives have substantially different profiles from a wildfire risk perspective. For the purpose of this Planning Study, a methodology based on the current Transmission Wildfire Risk Assessment and Mitigation Phase (RAMP) model was used to determine the relative contribution that each of the alternatives would make to increase the overall wildfire risk profile of the SCE system.

Currently, SCE's Transmission Wildfire Multi-Attribute Risk Score (MARS) baseline is 3.4[67] (out of 100) which is meant to demonstrate the relative risk exposure across SCE's portfolio. The MARS score is a unit-less value used to measure baseline risk, mitigation risk reductions (MRR), and the risk spend efficiency (RSE) of implementing various MMRs. To determine the potential increase in the baseline MARS score, the overhead circuit mileage of each alternative which is routed in Tier 2 and Tier 3 High Fire Risk Areas (HFRAs) is determined and multiplied by a representative incremental MARS per mile of overhead transmission factor. The results are summarized in Table 9-1.

[67] See Southern California Edison 2021 General Rate Case, "Risk Informed Strategy & Business Plan: SCE-01 Volume 02".

Table 9-1 – Incremental MARS Risk Contribution of Alternatives

Alternative	OH Length in HFRA (miles)	Incremental MARS Score	Percentage Increase Over MARS Baseline
SCE Orange County	24.6	0.015	0.43%
Alberhill	18.2	0.011	0.32%
SDG&E	16.2	0.010	0.29%
SDG&E with Centralized BESS in Valley South	16.2	0.010	0.29%
Mira Loma	4.9	0.003	0.09%
Mira Loma with Centralized BESS in Valley South	4.9	0.003	0.09%
Valley South to Valley North to Vista	3.8	0.002	0.07%
VS to VN to Vista with Centralized BESS in Valley South	3.8	0.002	0.07%
Menifee	1.2	0.001	0.02%
Centralized BESS	0.0	0.000	0.00%
VS to VN with Centralized BESS in Valley South	0.0	0.000	0.00%
Valley South to Valley North	0.0	0.000	0.00%
Valley South to Valley North and Distributed BESS in Valley South	0.0	0.000	0.00%

Table 9-1 demonstrates that the majority of the alternatives increase the baseline risk exposure to the overall wildfire risk profile of the SCE system, although the increase is minimal relative to the current baseline MARS score. The increase in risk as a whole is marginal and is therefore not incorporated into the cost models or considered a factor in evaluating the alternatives.

9.2. Volatility in Peak Load

The Valley South System currently serves peak load under normal weather conditions of approximately 1,000 MVA and is expected to experience load growth of approximately 10 MVA per year. The historical unadjusted recorded peak load values have demonstrated that the Valley South System can experience significant swings from year to year in the magnitude of peak load values and that even after typical normalizing adjustments are performed, a similar volatility remains present. This occurs because the system serves a large number of customers and even modest changes in circumstances can have dramatic impacts on the resulting electrical consumption.

Figure 9-1 shows that, for the Valley South System over the past ten years, the average year-over-year change (with some years being higher and some lower) in temperature-normalized loads was nearly 20 MVA. The two largest year-over-year swings were each over 50 MVA and were positive increases from the prior year. As seen in Figure 9-1, there are years where the year-over-year change was negative as well, with the actual total load growth averaging about 2% (~20 MVA) annually over that timeframe. This is important in that a forecast (represented generally by a forward-looking line reaching out over a time horizon) gives guidance directionally and in magnitude but does *not* represent the actual values that will occur year by year. Planning a solution to meet capacity needs predicated on the exact values that the forecast line suggests, and not fully acknowledging that the actual values likely to be recorded will deviate (both above and below) the forecast line, could result in a potentially significant underrepresentation of peak load values for any given year when load values fall above the line.

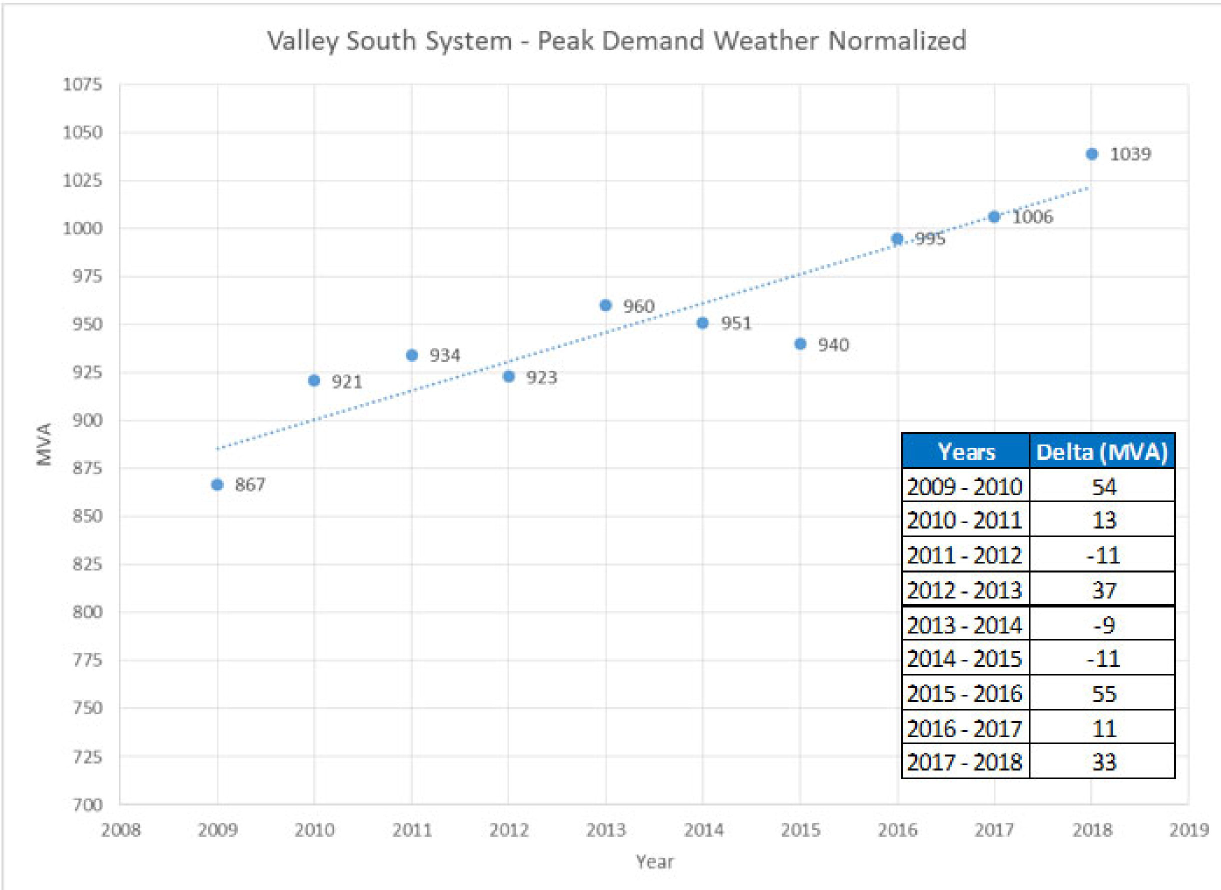

Figure 9-1 – Valley South System Peak Demand Weather Normalized

A consequence of relying on DER solutions applied incrementally to satisfy load growth is increased risk of being unable to serve load in a year that experiences peak demand that substantially exceeds the estimated demand. This element of risk is not accounted for in the cost-benefit analysis for NWA solutions. The risk can be effectively eliminated in Conventional Alternatives that provide additional inherent margin with respect to the forecast load.

9.3. Effects of Climate Change

Climate change that results in increased average and peak temperatures will have an effect on electricity demand and potentially, in extreme cases, to the behaviors and circumstances that drive the long-established correlation between temperature and load. Using historical load and closely correlated weather data, it was determined that when looking at peak temperatures, an increase in temperature of 1°F corresponds to an approximate 2.5 MVA increase in load at SCE's Auld Substation (representative of a centrally located and generally typical distribution substation within the Valley South System). Scaling this up to the full Valley South System (14 substations in total) results in a 35 MVA increase in load for every 1°F rise in temperature. Other system-wide data suggest this correlation may be as low as a 1.9% increase in load per degree Fahrenheit. This range suggests that should such an increase in peak temperature materialize, the resulting increase in load of the Valley South System's transformers would be equivalent to the increase in load over a 2 to 3-year period based on the current forecast (average growth of ~10MVA/year). The overall effect would accelerate and amplify future capacity and reliability/resiliency deficits, resulting in capacity shortfalls occurring earlier than expected for all alternatives.

9.4. Potential for Greater than Expected Electrification Rates

The SCE and SLF load forecasts utilize the IEPR DER growth rates for the years 2019-2028, at which point the SLF utilizes the California PATHWAYS model to predict DER growth rates from 2028-2048. The CEC 2050 scenario of the PATHWAYS model is used in the extended Effective PV and PVWatts SLF, and therefore includes the "High Electrification" scenario considered in alternative iterations of the model. However, the SLF only considers forecast vehicle electrification and does not consider forecast building electrification beyond that which is already included in historical data. Additionally, the Spatial Base SLF scenario does not consider any DER growth, i.e., building electrification and vehicle electrification are not included. Should the aggressive targets associated with the CEC 2050 scenario be reached, the load forecasts presented in this Planning Study would likely prove to under-predict future realized load beyond 2028. Accordingly, alternatives with capacity margin and which are therefore not reliant on BESS, such as the ASP, SDG&E and SCE Orange County, perform more favorably in this scenario.

9.5. Licensing Delays for Alternatives

For simplicity, and to ensure that alternatives were evaluated in the cost benefit analysis on the basis of the value they present to customers independent of timing, all alternatives were assumed to be in service concurrent with the 2022 project need date. ASP has been substantially vetted through regulatory and public scrutiny and has a current expected in-service date of 2025. While this in-service date could potentially be accelerated with an expedited project decision, the other alternatives have not yet been fully designed and developed and have yet to undergo analysis, public engagement, and regulatory review under CEQA. As described in detail in Appendix C of this Planning Study, many alternatives include miles of new lines routes, proposed facilities in undeveloped locations, and extensive easement requirements.[68] These alternatives are expected to have substantial challenges in licensing due to:

- the specific nature of the routes (heavily populated suburban areas, reservations or parks) and or affected communities not being directly served or benefited by the project;
- prior experience with engagement of the affected communities;
- unforeseen issues that may emerge through the CEQA process; and

[68] The site and route descriptions and associated characteristics affecting licensing durations (miles, property acquisitions, communities affected, undeveloped land, etc.) are described in Appendix C for each of the alternatives.

- required CAISO approval of the SDG&E alternative and risk of SDG&E opposition to relinquishing substantial capacity that would otherwise be available to support their own internal load growth.

As a result, several of these projects would be expected to have extended, multi-year licensing timelines that could extend to near the end of the ten-year project planning horizon, potentially resulting in risk and unrealized benefits to customers during this period or the need for other costly interim mitigations. For each year of delay, the reduction in overall benefits to customers would increase, starting from a range of $4.3M to $148M.[69] If these likely licensing delays and associated cost and benefit impacts were to be monetized in the cost-benefit analysis, the alternatives with expected longer licensing durations would perform much less favorably.

The consequence of project delays is risk of loss of service to customers which is masked to some extent in the assignment of probabilities to individual event scenarios. When one considers the real possibility of N-2 line and substation events occurring and that these probabilities are enhanced at periods of time when the systems are most vulnerable (high temperatures and high loading conditions), the consequences of these events are more apparent. For example, in considering the real possibility of a Flex-2-1 type event[70] occurring in 2028 on or near a peak load day without an appropriate project in place (i.e., one with adequate capacity and effective tie-lines and diverse location) the impact would be:

- Over 200,000 metered customers (>500,000 people) would lose service with no means to practically restore load in a timely manner

- The region would experience large scale economic impacts as well as disruption of public services

- Customer financial impact in the billions (based on VoS study outage costs as well as published costs of recent widespread outages)[71]

Similarly, while the impact on N-2 line outages would be somewhat more localized than for substation N-2 events, the consequences are also large. As an example, with no project in place, if a single 4-hour N-2 outage were to occur for the Valley-Auld #1 and Valley-Auld #2 115 kV lines (which have a number of common poles) on a peak day in 2028 approximately 35,000 customers would lose service for this period. Based on the VoS Study, the cost to customers of this single event would be on the order of $55M. Other credible line outage combinations would have similar impact. This economic impact occurs in both the case of substation and line N-2 events, because without a project to add capacity and serve load in an alternative manner (e.g., through transfers using system tie-lines), load shedding would be required to mitigate overload conditions. The ASP

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[69] In 2022, the Valley South to Valley North Alternative provides $4.3M and the ASP provides $148M of benefits to customers. These benefits increase in subsequent years.

[70] Total loss of the power delivery to the Valley South System for a 2-week (minimum) outage to (remove, transport, and replace transformers, repair bus work, replace power and control cables, etc.)

[71] https://www.cnbc.com/2019/10/10/pge-power-outage-could-cost-the-california-economy-more-than-2-billion.html

fully mitigates this loss of service to customers, while other alternatives provide only modest improvements at best. Table 9-2 below provides the cost to customers for this N-2 outage with each alternative implemented.

Table 9-2 - Customer Costs for Valley-Auld #1 and Valley-Auld #2 Outage: Peak Day in 2028

No Project	ASP	SDG&E	Mira Loma	SCE Orange County	VS-VN	VS-VN-Vista	Centralized BESS	Menifee
$55.6M	$0M	$44.4M	$55.6M	$55.6M	$55.6M	$55.6M	$44.9M	$55.6M

Note: Results for hybrid alternatives are not provided, as all BESS deployments for hybrid alternatives occur after 2028.

9.6. Licensing of Incremental Capacity Solutions

The regulatory pathways for licensing and implementing incremental energy storage projects or DER solutions are evolving in California and thus the ability to source the incremental capacity needs for some of the alternatives on a timely basis is uncertain. Similarly, the reliability of third-party delivery of these incremental capacity solutions is not yet proven to meet utility standards. Because these concerns are expected to be resolved well before these capacity additions are needed and associated costs are likely to be bounded by the costs of the modelled BESS alternatives, they are not considered to be significant risks.

9.7. Cannabis Cultivation Risk

SCE's planning department engages with local area businesses and customers to stay abreast of projects that may result in changes to electrical load. The cultivation of cannabis is a recent phenomenon that SCE estimates will result in an increase of approximately 5 MW in the Valley South System and 10 MW in the Valley North System within the ten-year planning horizon. This type of load is not represented in the historical data and is not included in the IEPR forecasts, nor is it explicitly represented in the Planning Study. Therefore, for any proposed solutions that seek to provide just enough capacity to meet the projected load without any additional marginal capacity, there is risk introduced that these particular solutions may not be sufficient to meet the demand should this load materialize.

9.8. Energy Storage Wholesale Market Revenue Risk

The current cost estimates for alternatives that employ BESS contain market revenue adjustments that bring down the overall cost of the solution. This market revenue is based on well-founded assumptions utilizing typical capacity and frequency regulation market participation scenarios, locational marginal pricing (LMP) data, and realistic round-trip efficiency models of BESS. There is uncertainty, of course, associated with these assumptions, particularly the LMP data, as the revenue gained from participating in wholesale markets can fluctuate from day-to-day and will vary in the future as market needs evolve. Particularly, as large-scale renewable energy developments in the Southern California region continue to drive down the total cost of generation,[72] the revenue realized by market participation may indeed be less than the figures estimated in this Planning Study.

9.9. Potential Need for 500 kV Generator Interconnection Facility

ASP is currently identified as the interconnection facility for the Lake Elsinore Advanced Pumped Storage (LEAPS) project[73] and, as designed, is able to accommodate a future interconnection. Should the LEAPS project be realized and a project other than ASP be selected, a new 500 kV substation (e.g., switching substation) would need to be developed in the area to support the LEAPS project as required by the Large Generator Interconnection Agreement (LGIA) between the developer of the LEAPS project and SCE.

9.10. Regulatory and Pricing Uncertainty for Demand Side Management Alternatives

Several forms of demand side management (DSM) were considered as part of SCE's alternatives analysis, including residential, non-residential, and plug-in electric vehicle (PEV) based load modifying DSM. Expansion of both residential and non-residential DSM programs currently in place would require either substantial changes in the regulatory framework (in the case of reliability offerings, a raising of the 2% cap on total system capacity[74]) or significant investment above and beyond current program expenditures with uncertain return given the current scale of DSM operations in the region. SCE's Customer Programs & Service organization analyzed existing programs and found that additional investment in the programs, without regulatory modification, would not result in any substantial reduction in future load beyond current capabilities. For economically dispatched programs, current scalable offerings in the residential space have reached a large degree of saturation for cost-effective DSM program participants in the region. Recent efforts to recruit new participants in the region have been to maintain the current levels of program capacity or have seen smaller incremental gains. With PEVs, a version of DSM would incorporate charging electric vehicle service equipment (e.g., PEV chargers) as a controlled load, effectively mitigating some portion of future load growth due to PEV adoption. However, there is significant uncertainty with this approach as very little historical data is available to make a reasonably accurate assessment of the impact of such a program.

Accordingly, for the purpose of this Planning Study, BESS are used as a surrogate for DSM program capacity/energy (or other DERs) that might ultimately be incorporated in Hybrid Alternatives. While it is recognized that DSM cost structures may vary from those of BESS, there is no framework to consider what these costs might be ten to thirty years from now to satisfy incremental capacity needs at that time. BESS costs are somewhat more predictable based on published long-term market data. Therefore, there is some risk that BESS costs in the cost benefit

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[72] See "Los Angeles OKs a deal for record-cheap solar power and battery storage", Los Angeles Times, Sept 20, 2019.

[73] The hydroelectric license application for LEAPS is currently pending before the FERC in Docket No. P-14227-003

[74] CPUC Decision D.10-06-034 adopted a reliability-based demand response settlement agreement that capped reliability-based demand response program that count toward resource adequacy at 2% of the recorded all-time coincident CAISO system peak, starting in 2014.

analysis model may be higher than those that might be realized in a future procurement of DSM resources. However, since these future costs are discounted heavily in the model and because DSM would almost certainly need to be augmented with some amount of BESS capacity due to the large capacity and energy needs that arise near the end of the evaluation period, it is unlikely that the results of the cost benefit analysis are substantially impacted by this assumption. From an implementation standpoint, if a hybrid alternative is selected, SCE can, under the appropriate regulatory framework at the time, build or source available front-of-the-meter and behind-the-meter DER technologies at market prices to meet the incremental capacity needs.

10.0 Basis for Preferred Alternative

This planning study confirms the need for a project and more specifically reinforces selecting a comprehensive solution for the Valley South System that addresses the transformer capacity shortfall forecast for 2022 and provides adequate system tie-lines to another system in order to improve reliability and resiliency. The ASP is SCE's recommended solution[75] to best address the defined objectives for the project based on a variety of factors. The ASP addresses the current and future capacity, reliability, and resiliency needs of the Valley South System, and most effectively meets all objectives defined at the onset of the project proceedings for the Valley South System. Further, the ASP is a long-term, cost-effective solution, and can be implemented in a reasonable time. Lastly, the ASP is a robust solution that limits SCE's risk exposure during unforeseen scenarios during implementation and while in operation.

Project Objectives

Serve current and long-term projected electrical demand requirements in the Electrical Needs Area (ENA). The ASP would meet the forecasted electrical demand and satisfy SCE Subtransmission Planning Standards and Guidelines related to substation transformer capacity until the year 2048.[76] ASP effectively addresses uncertainty and volatility in future load.

Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer substations from the current Valley South 115 kV System. The ASP would create the system tie-lines necessary to allow for operational flexibility and the ability to transfer substations from the Valley South System when needed for planned maintenance outages and to address multiple unplanned contingencies. The system analysis performed to support the 2019 data requests shows that the ASP would provide substantial available flexibility under specific contingency scenarios.[77]

Transfer a sufficient amount of electrical demand from the Valley South 115 kV System to maintain a positive reserve capacity on the Valley South 115 kV System through the 10-year planning horizon. The ASP would result in additional capacity in the region sufficient to provide positive reserve capacity on the Valley South System through and beyond the 10-year planning horizon.[78,79] In providing an additional source of

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[75] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item I.

[76] See Section 6.4 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C. The ASP satisfies transformation capacity needs far beyond 2048. A minor project to reconductor a single subtransmission line would be required in the 2038 time frame to satisfy N-1 line violation criteria through 2048.

[77] See Section 5 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item F.

[78] See Appendix B, Section 1, and Section 6.4 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

[79] The initial construction of the ASP is proposed to include two 560 MVA transformers of which one would be considered load-serving and the second would be an in-service spare. SCE notes that 1,120 MVA is a large amount of capacity to add to the system considering the incremental system needs of about 10 MVA per year. However, the

power it provides Valley South capacity relief without decreasing capacity margins in adjacent systems.

Provide safe and reliable electrical service consistent with SCE's Subtransmission Planning Criteria and Guidelines.[80] The ASP relieves all undesired exceptions to SCE's Subtransmission Planning Criteria and Guidelines that have been taken as the Valley South System has evolved.[81]

Increase electrical system reliability by constructing a project in a location suitable to serve the Electrical Needs Area (i.e., the area served by the existing Valley South System). The Final Environmental Impact Report (FEIR) and the analyses for the ASP demonstrate that the project siting and routing is attractive from the perspective of electrical system performance in serving the Electrical Needs Area. Its location in the San Jacinto Valley Region is within the area that directly benefits from the project. In addition to providing a second source of power to the region, the Alberhill Substation in the ASP is proposed in a geographic location distinct from Valley Substation where improvements to system reliability and resiliency would result.

Meet project need while minimizing environmental impacts. The ASP would meet the project need and has been determined in the FEIR to be the environmentally preferred alternative relative to the 30 alternatives considered therein ("FEIR Alternatives").

Meet project need in a cost-effective manner. As demonstrated in the cost-benefit analysis,[82] the ASP is a cost-effective solution. Among alternatives considered, the ASP is the lowest cost project alternative that fully satisfies the project objectives and capacity, reliability, and resiliency needs over both short and longer-term planning horizons.

Performance Metrics

SCE developed and evaluated the performance of a robust list of 12 project alternatives in addition to the ASP.[83] These alternatives included substations; subtransmission lines that transfer load to

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basis for this is as follows: 1) the ASP includes the addition of two transformers to satisfy SCE and industry-wide N-1 contingency planning criteria. These criteria require a subtransmission system be able to withstand an outage of any single subtransmission system element without disruption of service to customers. The second 560 MVA transformer is the on-site spare. 2) SCE's standard transformer size for 500/115 kV substations is 560 MVA and the potential savings from procuring a smaller capacity custom transformer is relatively small and would likely be offset by the costs of engineering and designing a non-standard transformer. 3) A uniquely sized 500 kV transformer would negate benefits achieved from using standard sized equipment between the 500/115 kV systems (i.e., Valley and Alberhill). 4) Lastly, approximately 400 MVA of demand is proposed to be initially transferred from the Valley South System to the Alberhill System and this equates to an approximate 70% utilization of the 560 MVA load-serving transformer initially and it is expected that this utilization would increase over time with load growth in the area.

[80] See SCE Subtransmission Planning Criteria and Guidelines 9/2015.

[81] See Table 4-1 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

[82] See Section 8.2 of DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

[83] The alternatives developed in response to this data request were based on a variety of inputs including stakeholder feedback and are in addition to the 30 "FEIR Alternatives" that were considered during the CEQA process and were

adjacent systems; battery energy storage systems (BESS); and combinations of the above. The ASP and these alternatives were evaluated using objective, quantitative, and forward-looking metrics to quantify their effectiveness in addressing capacity, reliability, and resiliency needs over time. The results showed:

- The ASP ranks first among the alternatives in terms of project performance in meeting objectives over both the 10-year (2028) and the 30-year (2048) planning horizons. The ASP resolves over 96%[84] of the projected capacity, reliability, and resiliency shortfalls in the region through 2048. Other alternatives resolve at most 83% of the projected shortfalls through 2048. When considering only lower-cost alternatives, only 34% of shortfalls are resolved through 2048. Similar percentage reductions are observed for the short-term (10-year planning horizon).
- All alternatives with lower costs than the ASP require SCE to implement incremental future investments to maintain compliance with SCE's Planning Criteria and Guidelines over the next 30 years and do not achieve system reliability and resiliency improvements comparable to the ASP. The ASP is the only solution that does not require incremental capacity additions to address electric service interruptions due to transformer capacity shortfalls through 2048. Menifee, a lower cost alternative that meets long-term capacity needs, does not have system tie-lines that are effective in transferring additional load from the Valley South System to an adjacent system during abnormal system conditions (e.g., N-1 or N-2 contingency conditions). The ineffective system tie-lines result from the Menifee alternative substation's location which is essentially adjacent to Valley Substation. Constructing effective system tie-lines at this location would require complex and expensive scope additions because of the location at the hub the Valley South System. Generally, and in this case, system tie-lines are most effective and economic when constructed near the periphery of a radial subtransmission system for reasons described in Section 8.2.1. Additionally, the proximity to Valley Substation introduces the potential vulnerability to HILP events affecting both Menifee and Valley substations and this vulnerability is not reflected in the resiliency metrics included in the current analysis.

Cost Effectiveness

The cost effectiveness of the ASP and alternatives to the ASP is evaluated by estimating the monetary value for each alternative from the perspective of the value of electric service to customers over total project costs. The ASP is cost effective in providing substantial benefits to customers. Specifically:

- The ASP has the best incremental benefit-to-cost ratio relative to alternatives considered, and among all sensitivity cases considered indicating that its increased benefits relative to these alternatives are cost effective.

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deemed less favorable than the ASP. The data request alternatives are described in detail in Section 6 and Appendix C. As directed by the CPUC, SCE did not evaluate any of the FEIR Alternatives other than the ASP in the data request submittals; as the ASP was already deemed to be superior to the FEIR Alternatives.

[84] Calculated as the total reduction in LAR for capacity, reliability, and resiliency metrics through 2048. See Table 6-2.

- The ASP has an overall benefit-to-cost ratio greater than nine, which is highly ranked among the 13 total alternatives in cost-benefit analysis and first among projects that meet project objectives. The other highly ranked alternatives that meet project objectives are the Mira Loma and SDG&E alternatives; however, these two alternatives violate the N-0 transformer overload system planning criteria (capacity) in 2031 and the 2040 time frame respectively and sooner under even modestly higher load forecast scenarios. This is an indication that they are less robust than ASP from a capacity perspective. When the subsequent investments needed to address the capacity violations and subsequent continuing incremental capacity needs (e.g., the addition of BESS over time to address capacity shortfalls) are considered, both the Mira Loma and SDG&E alternatives are ranked even farther below the ASP in terms of benefit-to-cost ratio.

Optionality and Risk

When considering a variety of optionality and risk factors including uncertainty and volatility in load, potential technology or market changes, and risks associated with project costs, ASP is the preferred solution over lower cost project alternatives to meet system needs over a shorter timeframe.

- ASP remains cost-effective under future low load growth and low -cost DER scenarios; while lower cost, short -term alternatives are not effective in addressing future higher load growth scenarios (such as might occur with enhanced electrification).
- ASP is more effective than lower cost, short -term alternatives in addressing other system performance risks such as those associated with year -to -year volatility in load and degraded capacity margins in adjacent systems.
- ASP has lower risk associated with ultimate licensing and cost of implementation than other alternatives that have not been subject to years of design, analysis and stakeholder engagement as has been the case for ASP. The project risks that could lead to higher costs or other concerns during the development, design and licensing include: required undergrounding commonly associated with projects with lengthy subtransmission lines constructed through congested areas; unknown geotechnical conditions; rerouting to avoid areas with stakeholder concerns and potential challenges associated in reducing capacity margins in the SDG&E system.

Timeliness of Project Implementation

SCE and other utilities propose projects well in advance of the need date in order to have infrastructure licensed, constructed, and operational in time to meet the need. Given the time required for licensing, SCE applied for a project in the Valley South System years in advance of its need, to avoid jeopardizing reliable service to its customers. The ASP licensing process has been underway for over a decade now. The need for a project in the Valley South System in the 2022 timeframe has been confirmed through SCE's supplemental analysis.[85] ASP has been substantially vetted through regulatory and public scrutiny and has a current expected in -service date of 2025. While this in -service date could potentially be accelerated with an expedited project

[85] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A.

decision, the other alternatives have not yet been fully designed or developed and have yet to undergo analysis, public engagement and regulatory review under CEQA. This additional work will result in continued project licensing costs to ratepayers and a higher probability of unexpected developments that would contribute to further delay.

A Appendix - Capacity, Reliability, and Resilience

Capacity is the availability of electric power to serve load and comprises two elements in a radial system: 1) transformation capacity – the ability to deliver power from the transmission system (provided by the substation transformers), and 2) subtransmission system line capacity – the ability to deliver power to substations which directly serve the customer load in an area. Both transformation capacity and subtransmission system line capacity include providing sufficient capacity under both normal and abnormal system conditions as well as under adverse weather conditions (e.g., 1-in-5 year heat storm conditions). Included in subtransmission system capacity is system tie-line capacity, the capacity to transfer load to an adjacent subtransmission system to maintain electrical service under a variety of system conditions or activities, such as planned outages for maintenance or new construction and unplanned outages. The lack of capacity of either type can lead to reliability challenges in a radial power system.

Reliability refers to a utility's ability to meet service requirements under normal and N-1 contingency conditions,[86] both on a short-term and long-term basis. Reliability is focused on the impacts to the electric grid and the associated effects on the day-to-day customer experience as it relates to power outages and durations thereof. It is conventionally quantified by metrics (such as those defined by IEEE-1366) that demonstrate how well a utility limits the frequency and duration of localized outages from factors such as equipment failure, animal intrusion, damage introduced by third parties, and the number of affected customers during these outages.

Resilience refers to a utility's ability to keep its systems functioning and serving customers under extraordinary circumstances.[87] Resilience is focused on how well the utility anticipates, prepares for, mitigates, and recovers from effects of extraordinary events. Wildfires, earthquakes, cyber-attacks, and other potential high impact, low probability (HILP) events can have widespread impact on the utility's ability to serve customers. Resilience also includes preparedness for long-term permanent changes such as the effects of climate change. Resilience is not just about continuing operations, but also is about the effectiveness of containing the impact of these extraordinary events and how efficiently and quickly a system and/or service is restored.

Key differences between reliability and resilience include:

Reliability

- Normal circumstances
- Localized impact
- Design redundancy
- System capacity/contingency-based planning criteria
- Customer outage focused

Resilience

- Extraordinary events
- Widespread impact
- Design and operations flexibility
- Comprehensive consideration of risk and mitigation
- Customer outage ***and*** utility operations focused

[86] An N-1 contingency is an unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element.

[87] See IEEE PES-TR65 "The Definition and Quantification of Resilience", April 2018 for more information.

B Appendix - History of the Valley Systems

B.1 Calectric Merger and Early History

Prior to 1964, the San Jacinto Valley Region was provided electrical service by the California Electric Company (Calectric). The region was served by the 115/33 kV Valley Substation (operated as a single radial subtransmission system) which was provided power by the 115 kV system from Vista Substation. Voltage was stepped down to 33 kV at Valley Substation and then distributed to the distribution substations via 33 kV source lines.

When SCE and Calectric merged in 1964, SCE became responsible for planning and operating these facilities. Long-range planning estimates from this era identified that due to projected load growth, the single 100 MVA 115/33 kV transformer that served the electrical needs of the entire 1,200 square-mile region would be insufficient to meet the growing demand and that system upgrades and additions would be required in the near-term future. These included capacity additions throughout the region (including capacity additions at Valley Substation and its distribution substations) and upgrades to the 33 kV source lines to the distribution substations emanating from Valley Substation to transport more power more efficiently. The 115 kV voltage was already present in the area as a source line to the Valley 115/33 kV Substation from the Vista 220/115 kV Substation to the north. It was determined that Valley Substation would eventually need to be converted to a higher voltage on the source side to deliver the additional required power and then the lower voltage 33 kV system would, at the same time, be converted to 115 kV. This would also then necessitate the conversion of the downstream 33/12 kV distribution substations to 115/12 kV. The 115 kV lines from the Vista System, previously providing the source power to Valley Substation, would be retained as subtransmission system tie-lines as part of a newly formed 115 kV system.

Throughout the 50,000 square mile service territory that resulted from the SCE and Calectric merger, the predominant transmission voltage was 220 kV, providing service to 220/115 kV and 220/66 kV A-bank substations. SCE's typical A-bank substations operating at these voltages were designed for an ultimate capacity of 1,120 MVA. Since it was projected that the ultimate load to be served in the entire San Jacinto Region would be approximately 1,000 MVA, Valley Substation was anticipated to be converted to a typical 220/115 kV transmission substation. In this case, new 220 kV transmission lines would have been constructed, from existing 220 kV facilities approximately 20 miles to the north, to provide the source power.

These plans were revised as new information became available. Load growth in Orange County and portions of Los Angeles County necessitated additional high-voltage transmission line facilities to deliver power from generation located further east. In the 1980s, a 500 kV transmission line was planned which would connect SCE's Serrano Substation in Orange County to SCE's Devers Substation in the Palm Springs area in order to deliver power from the Palo Verde generation station located in Arizona. Recognizing the transmission capacity needs of the coastal areas, along with the localized capacity needs in the San Jacinto Region, and that the planned route of the 500 kV line would pass near Valley Substation, the plan was then modified to convert Valley Substation to a 500/115 kV substation rather than a 220/115 kV substation, as this would involve significantly less transmission line construction. The resulting 500 kV lines would be the Devers-

Valley and Serrano-Valley 500 kV Transmission Lines, and Valley Substation would become a 500/115 kV A-bank substation.

The conversion of Valley Substation included leveraging the high capacity of the 500 kV transmission system to deliver power to the area by installing two 560 MVA 500/115 kV transformers (versus the typical 280 MVA transformers used at 220/115 kV or 220/66 kV substations) with one to serve demand and the other to function as a spare. The distribution substation source lines were rebuilt and converted from 33 kV to 115 kV and the distribution substations were rebuilt to 115/12 kV. With the newly created 115 kV lower voltage subtransmission system, the original 115 kV source lines to Valley Substation were then used as 115 kV subtransmission system tie-lines to the Vista 220/115 kV System.[88]

In 1984, the new Valley 500/115 kV System conversion was complete. The new radial 115 kV system served the entire 1,200 square-mile San Jacinto Region, including what is currently the Valley North and Valley South 115 kV Systems. Over time, more of the agricultural land was rezoned for development, and in the late 1980s it became apparent that the 1,000 MVA anticipated ultimate demand expected for the area was significantly underestimated. Prior to electrical demand exceeding the capacity of the single 560 MVA load-serving transformer, the existing spare transformer was converted to function as load-serving and a new spare was ordered and installed. This resulted in Valley Substation consisting of a single 115 kV radial system served by two 560 MVA transformers with a third transformer functioning as an on-site spare.

In the early 2000s, the area experienced further unprecedented growth in electrical demand due to housing development as more and more people elected to reside in the San Jacinto Region and commute to Orange and San Diego Counties. Planning activities identified that by 2003, peak demand would exceed the installed transformer capacity at Valley Substation. Both immediate and long-term solutions were needed. As before, SCE placed the existing spare transformer in-service and ordered and installed a new spare. However, load growth in this area was continuing at a very high rate (75-100 MVA per year or ~8% annually) and it was expected that, within just a few years, additional capacity would again be needed.

B.2 Developing a Long-Term Solution

Along with having three load-serving 560 MVA 500/115 kV transformers operating electrically in parallel and needing further transformation capacity to address load growth, SCE identified several other issues that needed to be resolved in the Valley System. These included short-circuit current values that were exceeding or encroaching on equipment ratings as well as reliability and resiliency concerns of serving so many customers over such a large area from a single radial electrical system.

By this time, the California Public Utilities Commission General Order 131-D was in place and the time required to perform the necessary environmental studies and obtain approvals would not allow for a long-term solution to be constructed before the capacity of the three transformers was

[88] These 115 kV system tie-lines currently connect the Valley North System to the Vista System.

projected to be exceeded. As an interim solution, in 2004, SCE decided to split the single 115 kV system into two separate 115 kV systems (Valley North and Valley South) by constructing new facilities at Valley Substation and placing the spare transformer in-service as the fourth load-serving transformer. The substation was configured so there would be two transformers serving each system. The scope of work included constructing a new 115 kV switchrack on the south end of the property, converting the spare transformer to a load-serving transformer, connecting two of the four transformers to each 115 kV switchrack, and reconfiguring the 115 kV lines to roughly split the load between the two systems. By 2005, this work had been completed.[89] The resulting design met the immediate transformer capacity needs but left other issues to be resolved through the development of a long-term solution.

The first unresolved issue included addressing the long-term reliability needs of the region, which included assessing A-bank substation transformer capacity and system transfer capacity (i.e., sufficient system tie-line capacity). A second unresolved issue was to address the resiliency vulnerabilities associated with serving such a large customer base from a single radial A-bank substation - particularly considering its unique 500/115 kV transformers which precluded having ready access to spares as would have been the case with the typical 220/66 kV or 220/115 kV transformers. Associated with both reliability and resiliency, was the need to address that the Valley South System had no system tie-lines. Following the in-servicing of the fourth transformer and splitting the Valley System into two separate electrical systems, the existing four system tie-lines to the Vista System were now all part of the newly formed Valley North System and thus the Valley South System was left with none. Finally, after placing the existing spare transformer in-service to serve load, Valley Substation (and the Valley North and Valley South Systems) were left without a spare transformer. This was inconsistent with SCE's planning criteria and was also inconsistent with how SCE had designed its other radial electrical systems.

In developing a long-term solution to address the expected future growth and to the unresolved issues identified above, SCE evaluated past load growth trends and anticipated future load growth projections as well as expected changes in land use and load types that would affect load. This led SCE to review various solutions to meet the anticipated needs in both the near-term and long-term horizons. These solutions included load-shifting from system to system, transformer capacity additions, system tie-line creation, and generation. The fundamental requirements of any solution were to address transformer capacity deficits, lack of system tie-lines, and the diversification of the sources of power that would serve the region.

B.3 Alberhill System Project

The long-term planning demonstrated that the load growth potential of the region would require significantly more capacity than what could be served from Valley Substation, due primarily to transformer capacity needs and a lack of system tie-lines. Given the long-term forecast based on an unprecedented development boom, and prior to the proliferation of distributed generation in the form of roof-top PV, SCE identified a future need for multiple new A-bank transmission substations (and their associated new radial electrical systems) over time as development

[89] This work resulted in the current system configuration which is shown in Figure 3-2.

continued. This would be a comprehensive method for addressing the long-term electrical needs of the region by adding transformer capacity, addressing the lack of system tie-lines, and diversifying the sources of power.

The ASP was the initial preferred option for these new regional electrical improvements because: 1) the Valley South System had the most immediate transformer capacity need; 2) the Valley South System had no system tie-lines (inconsistent with SCE's planning practices) and was therefore isolated from adjacent electrical systems; and 3) the Alberhill System Project would have the least amount of transmission line related scope and was therefore expected to be completed soonest.

The Alberhill System Project will address capacity and reliability issues in the Valley South System specifically, and in addition, improve the resiliency of the larger Valley System. The Alberhill System Project includes the construction of a new 500/115 kV substation with two 500/115 kV 560 MVA transformers and the formation of system tie-lines between the newly constructed Alberhill System and the existing Valley South System. Approximately 400 MVA of electrical demand would be served through the initial transfer of five 115/12 kV distribution substations (Ivyglen, Fogarty, Elsinore, Newcomb, and Skylark) and would reduce the loading on the Valley South System. The transfer of these substations was chosen due to their proximity to the Alberhill Substation site, as well as the amount of load relief that would be provided to the Valley South System. The project strives to minimize the amount of new 115 kV line construction and/or reconfiguration required to achieve the transfers, with consideration of the tie-line capacity that would be created. Figure B-1 shows the proposed new Alberhill System in the context of the Valley North and Valley South Systems.

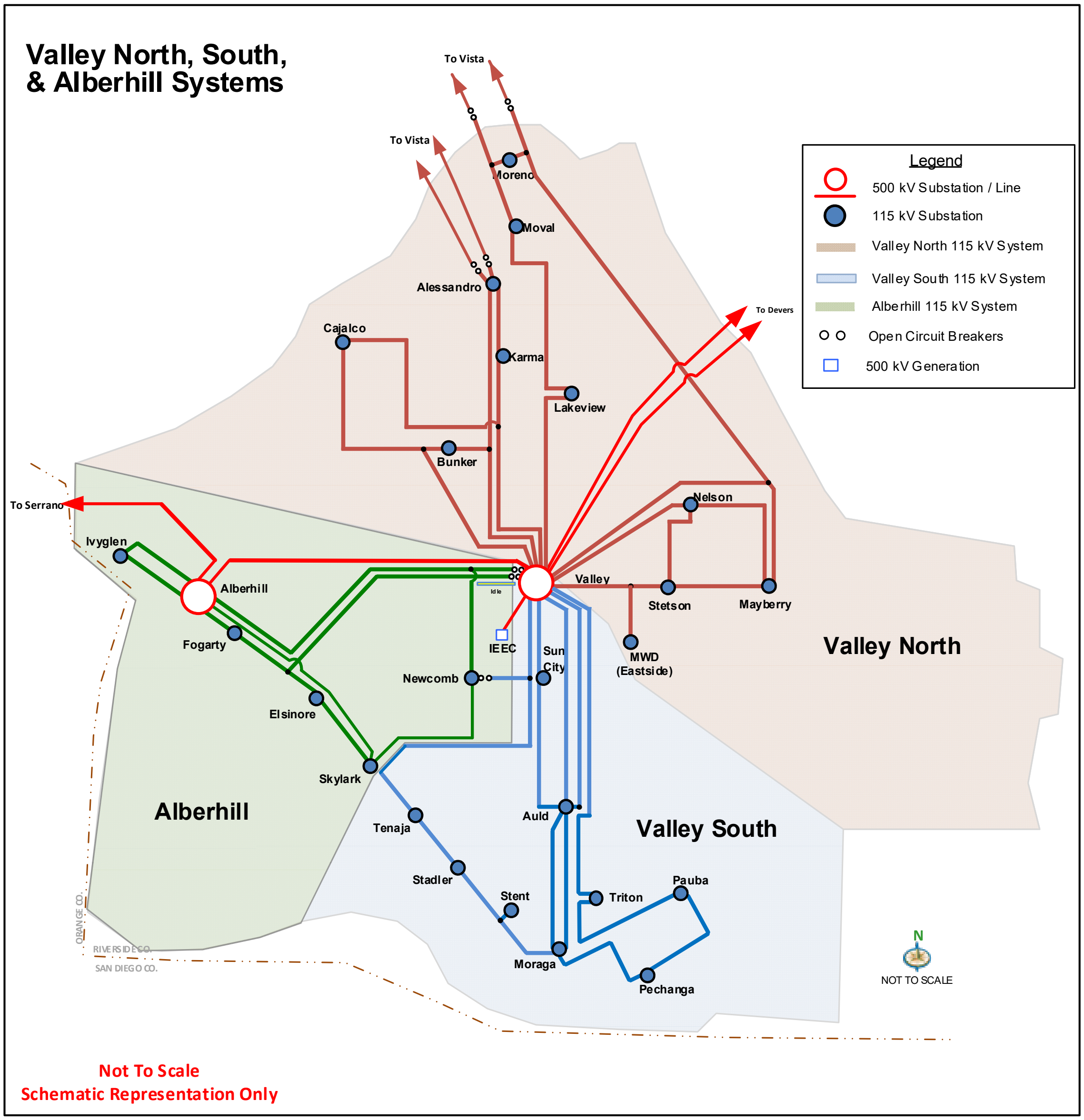


Figure B-1 – Proposed Alberhill, Valley South, and Valley North Systems

While load growth in the Valley South System slowed from the extraordinary levels seen through the early 2000s, load growth is continuing through today and the future need for additional capacity that was first identified in 2005 has now reached a critical point.[90] The current lack of sufficient transformer capacity margin, particularly coupled with limited operational flexibility resulting from the lack of system tie-lines, is a near-term threat to the reliability of the Valley South System. Additionally, the resiliency of the Valley South System continues to be limited because it is served

[90] This fact is reflected in sequential SCE 2017 and 2018 load forecasts covering the years 2018-2027 and 2019-2028 respectively. The additional, independent load forecasts provided in this Planning Study underscore the criticality of this project.

from a single source of power at Valley Substation and because it has no system tie-lines to at least partially mitigate the potential loss of service from certain power lines within the system and/or an unplanned outage of all or part of the Valley Substation.

The Alberhill System Project would meet the project objectives by adding A-bank substation transformer capacity and system tie-line capacity to the existing area served by the Valley South System while also diversifying the location of the new power source to the area. The reliability and resiliency of the entire region would be greatly improved by increasing the transformer capacity, adding system tie-lines (absent since 2005), and diversifying the locations of the source power.

C Appendix – Project Alternatives Descriptions

This appendix provides details of the project alternative system overviews, schematics, siting and routing descriptions and maps, implementation scope, and cost estimates.

C.1 Alberhill System Project

C.1.1 **System Solution Overview**

The Alberhill System Project (ASP) proposes to transfer load away from Southern California Edison's (SCE) existing Valley South 500/115 kilovolt (kV) System to the new 500/115 kV Alberhill System via construction of a new 500/115 kV substation and looping in the Serrano-Valley 500 kV transmission line. The project would include 115 kV subtransmission line scope to transfer five 115/12 kV distribution substations (Fogarty, Ivyglen, Newcomb, Skylark and Elsinore) currently served by the Valley South System to the new Alberhill System. Subtransmission line construction and modifications in the Valley South System would also create three system-ties between the Valley South System and the newly formed Alberhill System. The system-tie lines would allow for the transfer of load from the new Alberhill System back to the Valley South System (one or all of Fogarty, Newcomb, Skylark and Elsinore) as well as additional load transfer from the Valley South System to the new Alberhill System (Tenaja Substation) as needed.

C.1.2 **System One-Line Schematic**

A System One-Line Schematic of the ASP is provided in Figure C-1 on the following page.

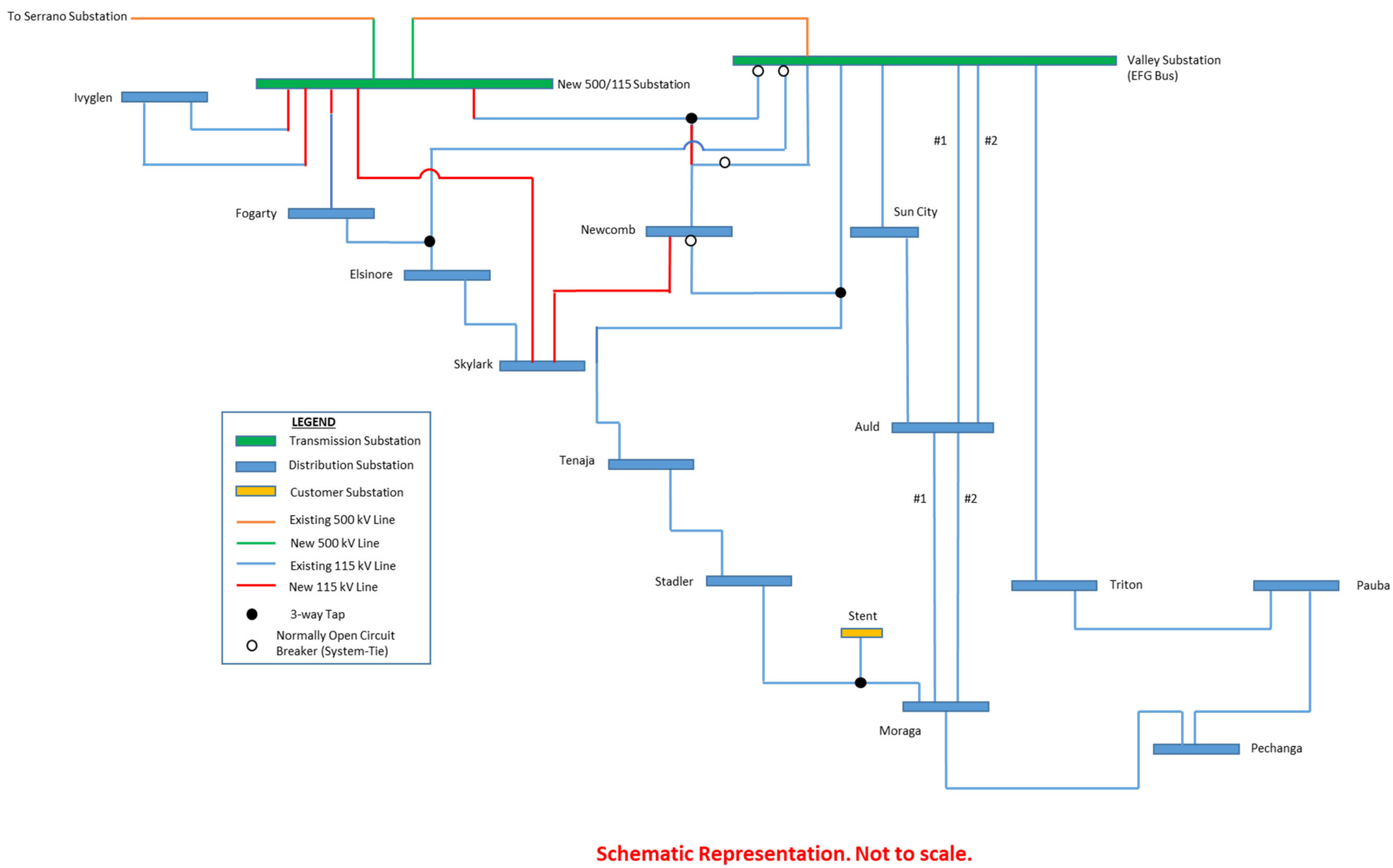


Figure C-1. System One-Line Schematic of the ASP

C.1.3 **Siting and Routing Description**

This project would include the following components:

- Construct a new 500/115 (kV) substation (approximately 40-acre footprint)

- Construct two new 500 kV transmission line segments between the existing Serrano-Valley 500 kV transmission line and the new 500/115 kV substation (approximately 3 miles)

- Construct a new double-circuit 115 kV subtransmission line and modifications to existing lines between the new 500/115 kV substation and SCE's existing five 115/12 kV distribution substations: Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb (approximately 21 miles)

This project would require the construction of approximately 24 miles of new or modified 500 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided in the subsections that follow.

New 500/115 kV Substation

The ASP would include the construction of a new 500/115 kV substation on approximately 40 acres of a privately owned, 124-acre property. The parcel is located north of the I-15 and the intersection of Temescal Canyon Road and Concordia Ranch Road in unincorporated western Riverside County.

New 500 kV Transmission Lines

Two new 500 kV transmission lines would be constructed, connecting the new 500/115 kV substation to the existing Serrano-Valley 500 kV transmission line. This new 500 kV transmission line would begin at the new 500/115 kV substation approximately 0.2 miles northeast of the corner of the intersection of Temescal Canyon Road and Concordia Ranch Road. The lines would leave the substation on new structures extending to the northeast for approximately 1.5 miles. Both lines will connect and be configured into the existing Serrano-Valley 500 kV transmission line.

New 115 kV Subtransmission Lines

New 115 kV subtransmission lines would be constructed, connecting the new 500/115 kV substation to SCE's existing five 115/12 kV substations (Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb substations). The lines would depart the new 500/115 kV substation on new structures and would intersect with existing 115 kV lines along Temescal Canyon Road and Concordia Ranch Road. A second 115 kV circuit would be installed on existing structures along Concordia Ranch Road, to the corner of Collier Avenue and Third Street in the City of Lake Elsinore. Along Third Street, new double-circuit structures would be installed from Collier Avenue to Second Street, and would be terminated to an existing, idle 115 kV line located on the north side of Interstate 15. Existing 115 kV structures would be replaced with double-circuit structures from East Flint Street and East Hill Street to Skylark Substation, and from Skylark Substation to the intersection of Bundy Canyon Road and Murrieta Road. At this intersection, a new single-circuit 115 kV line would be constructed to Newcomb Substation.

C.1.4 **Siting and Routing Map**

A siting and routing map of the ASP is provided in Figure C-2 on the following page.

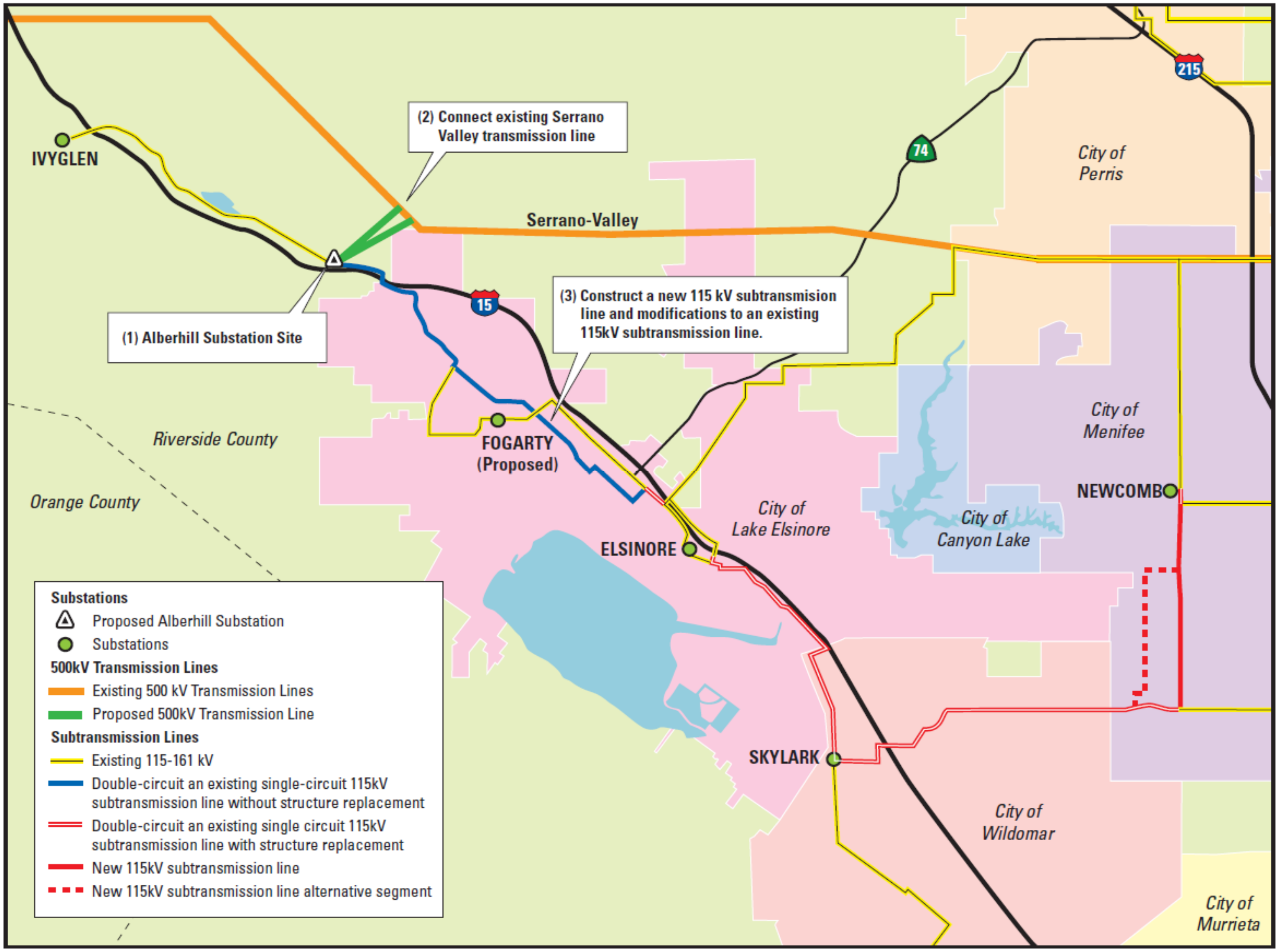


Figure C-2. Siting and Routing Map for the ASP

C.1.5 **Project Implementation Scope**

Table C-1 summarizes the scope for this project.

Table C-1. ASP Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 500/115 kV Station	
Electrical	New (6) position, (4) element 500 kV breaker-and-a-half switchrack to accommodate (2) transformers & (2) lines
	(2) 560 MVA, 500/115 kV transformers
	New (9) position, (7) element 115 kV breaker-and-a-half switchrack to accommodate (2) transformers & (5) lines
	500 ad 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecommunications IT	(1) Mechanical Electrical Equipment Room (MEER) & (1) Microwave Tower
New 500 kV Transmission Line	
Loop-in Serrano-Valley 500 kV Line into New 500/115 kV Substation	3.3 miles overhead single-circuit
New 115 kV Subtransmission Lines	
New Substation to Valley, Ivyglen, Fogarty, Skylark, and Newcomb	11.3 miles overhead double-circuit, 3 miles overhead single-circuit, 6.3 miles overhead double-circuit existing
Support Scope Elements	
Substation Upgrades	
Serrano	(1) 500 kV line protection upgrade
Valley	(1) 500 kV & (1) 115 kV line protection upgrade
Fogarty	(1) 115 kV line protection upgrade
Skylark	(1) 115 kV line protection upgrade
Newcomb	(1) 115 kV line protection upgrade
Ivyglen	(2) 115 kV line protection upgrades
Elsinore	(1) 115 kV line protection upgrade
Distribution	
Station Light & Power – New Single-Circuit Underground	Approximately 900 feet
Replace Existing Underbuild	Approximately 20 miles
Transmission Telecom	
New Fiber Optic Line	8.7 miles (7.6 overhead, 1.11 underground) fiber optic cable
Real Properties	
500 kV Transmission Line	New Easement – (5) Parcels (2.3 miles, 200 ft. wide, 56.6 acres total)
115 kV Subtransmission Line	New Easement – (80) Parcels (27 miles, 10 ft. wide, 33 acres total)

Scope	Detailed Scope Element
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.1.6 **Cost Estimate Detail**

Table C-2 summarizes the costs for this project.

Table C-2. ASP Cost Table

Project Element	Cost ($M)
Licensing	27
Substation	215
Substation Estimate	196
Owners Agent (10% of construction)	19
Corporate Security	4
Bulk Transmission	53
Subtransmission	51
Transmission Telecom	0
Distribution	4
IT Telecom	7
RP	34
Environmental	28
Subtotal Direct Cost	**424**
Subtotal Battery Cost	**n/a**
Uncertainty	121
Total with Uncertainty	**545**
Total Capex	**545**
PVRR	**474**

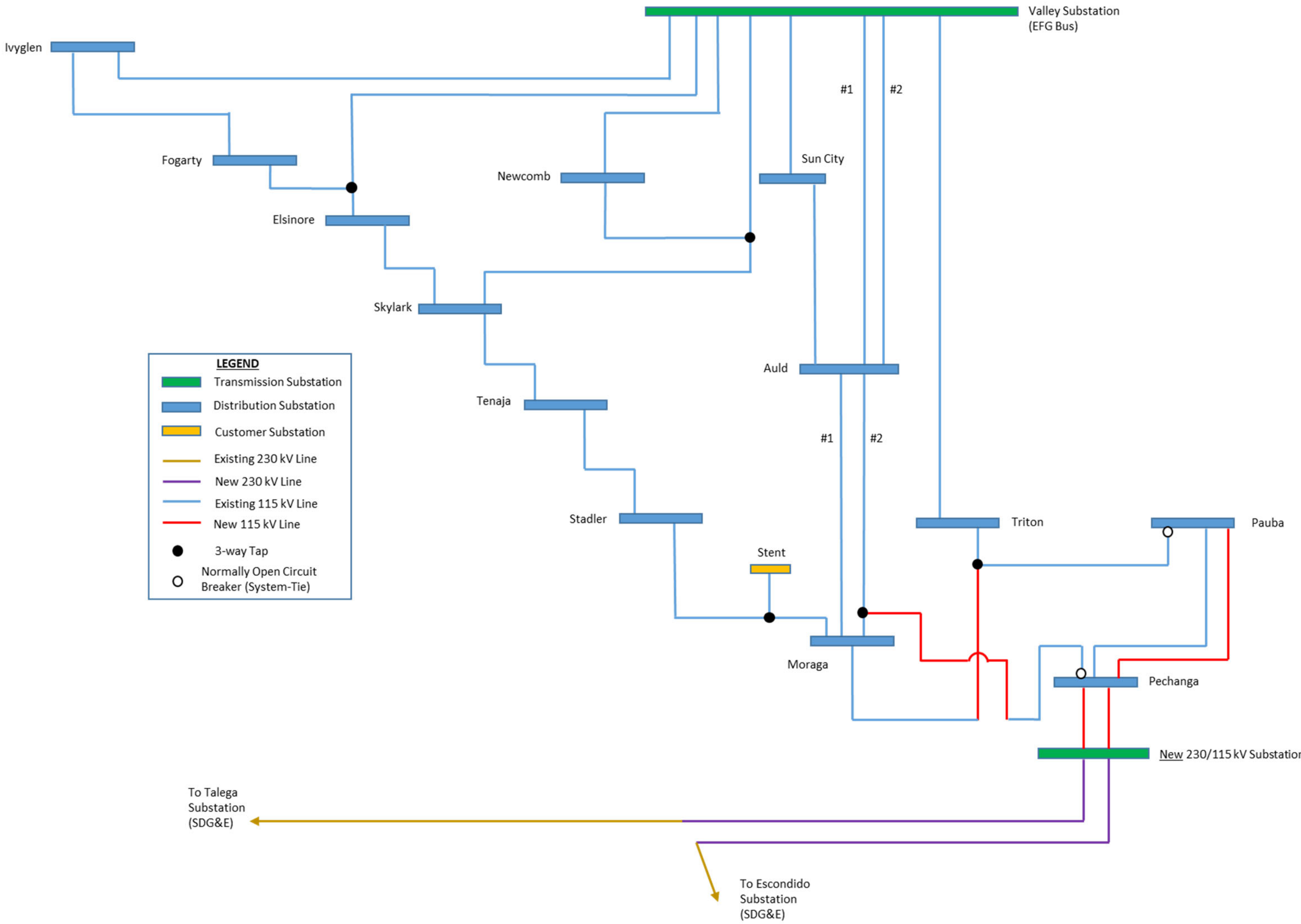
C.2 SDG&E

C.2.1 System Solution Overview

The San Diego Gas and Electric (SDG&E) alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 230/115 kV system created at the southern boundary of the SCE service territory and adjacent to SDG&E's service territory. The new system would be provided power from the existing SDG&E 230 kV system via construction of a new 230/115 kV substation and looping in the SDG&E Escondido-Talega 230 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Pauba and Pechanga 115/12 kV distribution substations to the newly formed 230/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two 115 kV system-ties between the Valley South System and the newly formed 230/115 kV SDG&E-sourced system. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Pauba and Pechanga Substations) as well as additional load transfer from the Valley South System to the new system (Triton Substation) as needed.

C.2.2 System One-Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-3 on the following page.



Schematic Representation. Not to scale.

Figure C-3. System One-Line Schematic of the SDG&E Alternative

C.2.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 230/115 kV substation (approximately 15-acre footprint)
- Construct a new 230 kV double-circuit transmission line segment between SDG&E's existing Escondido-Talega 230 kV transmission line and SCE's new 230/115 kV substation (approximately 7.2 miles)
- Construct a new 115 kV double-circuit subtransmission line between SCE's new 230/115 kV substation and SCE's existing Pechanga Substation (approximately 2 miles)
- Demolish SCE's existing 115 kV switchrack at Pechanga Substation and reconstruct it on an adjacent parcel (approximately 3.2-acre footprint)
- Double-circuit SCE's existing Pauba-Pechanga 115 kV subtransmission line (approximately 7.5 miles)
- Double-circuit a segment of SCE's existing Auld-Moraga #2 115 kV subtransmission line (approximately 0.3 mile)

This system alternative would require the construction of approximately 9.2 miles of new 230 kV transmission and 115 kV subtransmission lines and the modification of approximately 7.8 miles of existing 115 kV subtransmission line. This system alternative totals approximately 17 miles of line construction. A detailed description of each of these components is provided in the subsections that follow.

<u>New 230/115 kV Substation</u>

The SDG&E alternative would include the construction of a new, approximately 15-acre, 230/115 kV substation on a privately owned, approximately 56-acre, vacant parcel. The parcel is located north of Highway 79, between the intersections with Los Caballos Road and Pauba Road, in southwestern Riverside County. The parcel is trapezoidal in shape and is bounded by residences and equestrian facilities to the north, east, and west; and Highway 79 and vacant land to the south. SCE may establish vehicular access to the site from Los Corralitos Road or Highway 79.

<u>New 230 kV Double-Circuit Transmission Line</u>

A new 230 kV double-circuit transmission line would be constructed, connecting the new 230/115 kV substation to SDG&E's existing Escondido-Talega 230 kV transmission line. This new 230 kV transmission line would begin at SDG&E's existing 230 kV Escondido-Talega 230 kV transmission line approximately 0.6 miles northeast of the intersection of Rainbow Heights Road and Anderson Road in the community of Rainbow in San Diego County. The line would leave the interconnection with SDG&E's existing Escondido-Talega 230 kV transmission line on new structures extending to the northeast for approximately 0.8 miles. At this point, the new line would enter Riverside County and the Pechanga Indian Reservation for approximately 4 miles. The line would continue in a generally northeast direction for approximately 1 mile before exiting the Pechanga Indian Reservation[91] and continue until intersecting Highway 79. At the intersection with Highway 79, the new transmission line would extend northwest and parallel to Highway 79 for approximately 1 mile until reaching the new 230/115 kV substation. This segment of the system alternative would be approximately 7.2 miles in length.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line would be constructed to connect the new 230/115 kV substation to SCE's existing 115/12 kV Pechanga Substation. The line would depart the new 230/115 kV substation to the northwest on new structures for approximately 1.5 miles while traveling parallel to Highway 79. Near the intersection of Highway 79 and Anza Road, the line would transition to an underground configuration and continue along Highway 79 for approximately 0.5 miles until reaching SCE's existing 115 kV Pechanga Substation. This segment of the system alternative would be approximately 2 miles in length.

Demolish and Reconstruct an Existing 115 kV Switchrack

SCE currently operates the existing 115 kV Pechanga Substation, located on an approximately 3.2-acre, SCE-owned parcel approximately 0.2 miles northeast of the intersection of Highway 79 and Horizon View Street. This site is bounded by vacant land to the east and west and residential uses to the north and south. SCE would demolish this existing 115 kV switchrack and reconstruct it on an approximately 16.9-acre, privately owned parcel directly east of the existing substation. The new 115 kV switchrack would occupy approximately 3.2 acres within the parcel.

Double-Circuit Existing 115 kV Subtransmission Lines

Pauba-Pechanga

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Pauba and Pechanga Substations in southwestern Riverside County. This existing line would be converted to a double-circuit configuration, adding a new 115 kV circuit between SCE's existing 115 kV Pauba and Pechanga Substations. The existing line departs SCE's existing 115 kV Pechanga Substation and extends east along Highway 79 until reaching Anza Road. At the intersection of Highway 79 and Anza Road, the line extends northeast along Anza Road until reaching De Portola Road. At this intersection, the line extends generally northeast along De Portola Road until intersecting Monte de Oro Road, then the line extends west along Monte de Oro Road until reaching Rancho California Road. At this point, the line extends south

[91] Approximately 0.5 miles of this segment of the line would be located outside of the Pechanga Reservation.

along Rancho California Road and terminates at SCE’s existing 115 kV Pauba Substation. This segment of the system alternative is approximately 7.5 miles in length.

Auld-Moraga #2

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE’s 115 kV Auld Substation in the City of Murrieta and SCE’s existing 115 kV Moraga Substation in the City of Temecula. An approximately 0.3-miles segment of this line within the City of Temecula would be converted from a single-circuit to double-circuit configuration. This segment would begin near the intersection of Rancho California Road and Calle Aragon. The existing line then extends south before turning west and intersecting Margarita Road, approximately 0.2 miles northwest of Rancho Vista Road.

C.2.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-4 on the following page.

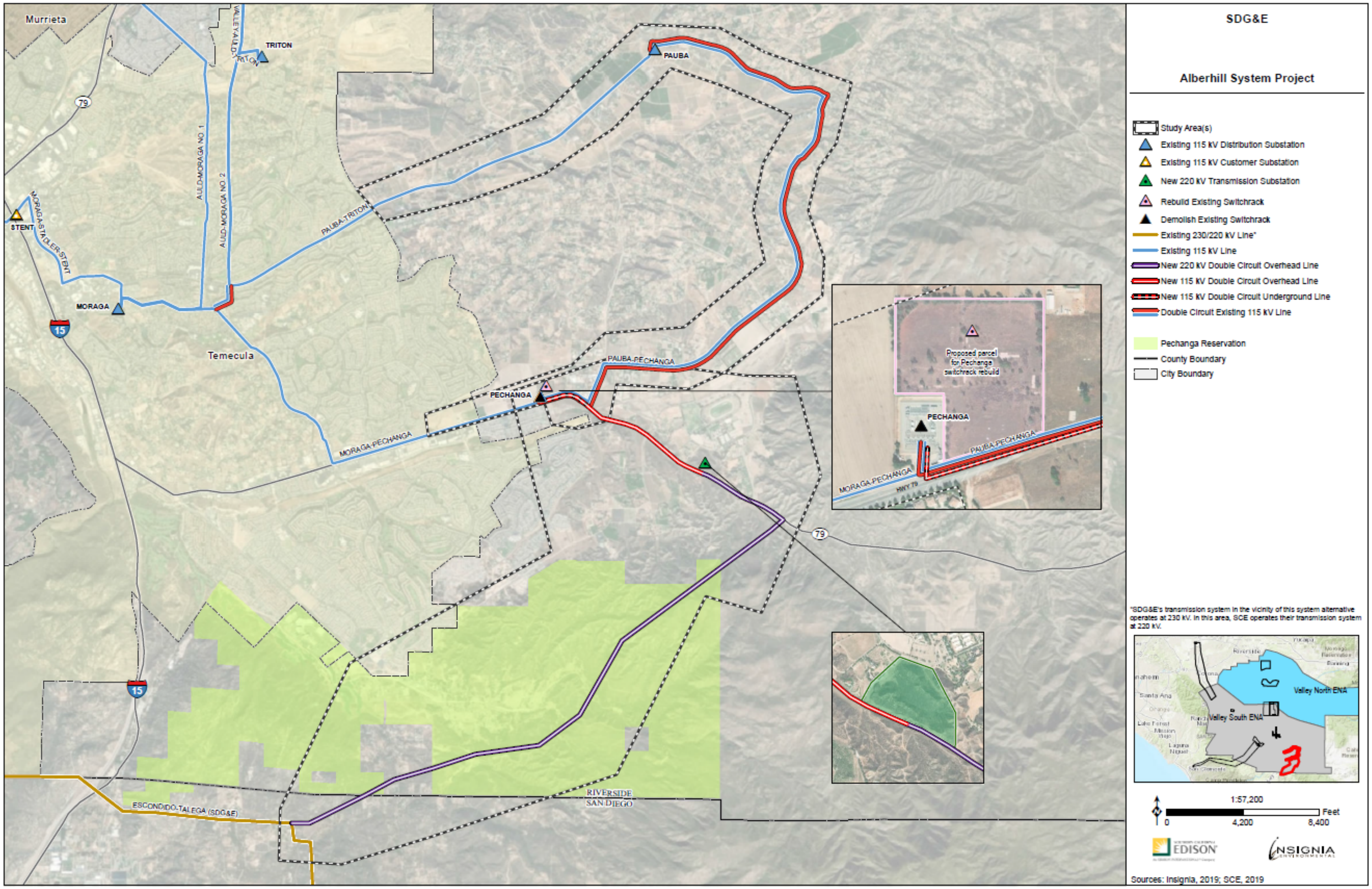


Figure C-4. Sitting and Routing Map for the SDG&E Alternative

C.2.5 Project Implementation Scope

Table C-3 summarizes the scope for this alternative.

Table C-3. SDG&E Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 230/115 kV Substation	
Electrical	New (3) position, (4) element 230 kV breaker-and-a-half switchrack to accommodate (2) banks & (2) lines
	(2) 280 MVA, 230/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	230 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 230 kV Transmission Line	
Loop-in SDG&E Escondido-Talega 230 kV line into New 230/115 kV Substation	7.3 miles overhead double-circuit 230 kV line
New 115 kV Subtransmission Line	
New 230/115 kV Substation to Pechanga Substation	2 miles (1.4 overhead double-circuit, 0.6 underground double-circuit)
Pauba-Pechanga	7.5 miles overhead double-circuit existing
Moraga-Pauba-Triton	0.3 miles overhead double-circuit existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Escondido	(1) 230 kV line protection upgrade
Moraga	(1) 115 kV line protection upgrade
Pechanga	
Civil	Demo the existing 115 kV switchrack
	Extend existing perimeter fence with a guardian 5000 fence
Electrical	New (6) position, (8) element 115 kV BAAH switchrack to accommodate (3) transformers & (5) lines
	New 115 kV line protection. Replace bank protection.
	HMI upgrade
Talega	(1) 230 kV line protection upgrade
Triton	(1) 115 kV line protection upgrade
Pauba	Equip (1) 115 kV line position; (1) 115 kV line protection upgrade

Scope	Detailed Scope Element
Distribution	
Station Light & Power – New Single-Circuit Underground	Approximately 3,300 feet
Replace Existing Single-Circuit Underbuild	Approximately 24,200 feet
Replace Existing Double-Circuit Underbuild	Approximately 17,200 feet
Transmission Telecom	
SDG&E Escondido-Talega 230 kV line to New 230/115 Substation	7.3 miles overhead fiber optic cable
New 230/115 kV Substation to Pechanga Substation	2 miles (1.4 miles overhead, 0.6 miles underground) fiber optic cable
Pauba-Pechanga	7.5 miles overhead fiber optic cable
Moraga-Pauba-Triton	0.3 miles overhead fiber optic cable
Real Properties	
SDG&E Substation A-A-04	Fee Acquisition – (1) 11.01-Acre Parcel
Pechanga Substation B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
SDG&E 230 kV Transmission Line	New Easement – (10) Parcels (2.5 miles, 100 ft. wide, 30.3 acres total)
SDG&E 115 kV Subtransmission Line	New Easement – (6) Parcels (2 miles, 30 ft. wide, 7.3 acres total)
Pauba-Pechanga 115 kV Subtransmission Line	New Easement – (9) Parcels (1.5 miles, 30 ft. wide, 5.5 acres total)
Auld-Moraga #2 115 kV Subtransmission Line	New Easement – (4) Parcels (0.33 miles, 30 ft. wide, 1.2 acres total)
SDG&E Laydown Yards	Lease – (2) 15-Acre Parcels for 96 months
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 230/115 kV Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.2.6 **Cost Estimate Detail**

Table C-4 summarizes the costs for this alternative.

Table C-4. SDG&E Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	99
Substation Estimate	82
Owners Agent (10% of construction)	16
Corporate Security	3
Bulk Transmission	112
Subtransmission	42
Transmission Telecom	3
Distribution	6
IT Telecom	4
RP	20
Environmental	40
Subtotal Direct Cost	**359**
Subtotal Battery Cost	**n/a**
Uncertainty	181
Total with Uncertainty	**540**
Total Capex	**540**
PVRR	**453**

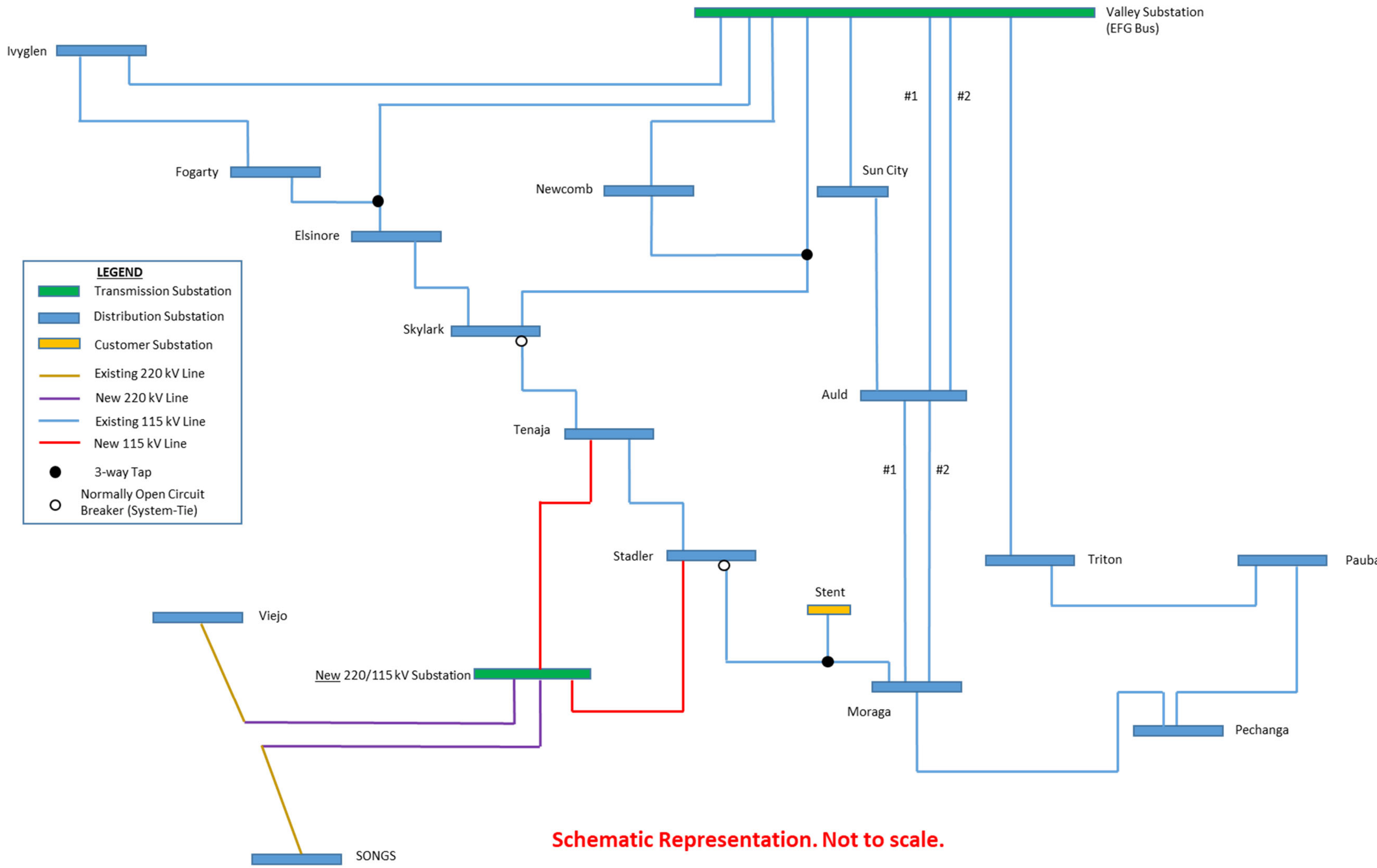
C.3 SCE Orange County

C.3.1 System Solution Overview

The SCE Orange County alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system via construction of a new 220/115 kV substation and looping in the SONGS-Viejo 220 kV line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Stadler and Tenaja 115/12 kV distribution substations to the newly formed 220/115 system. The existing 115 kV subtransmission lines serving Stadler and Tenaja substations would become two system-ties between the new 220/115 kV system and the Valley South System. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Stadler and Tenaja Substations) as well as additional load transfer from the Valley South System to the new system (Skylark or Moraga Substation) as needed.

C.3.2 System One-Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-5 on the following page.



Schematic Representation. Not to scale.

Figure C-5. System One-Line Schematic of the SCE Orange County Alternative

C.3.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 220/115 kV substation (approximately 15-acre footprint)
- Construct a new 220 kV double-circuit transmission line segment between SCE's existing San Onofre-Viejo 220 kV transmission line and SCE's new 220/115 kV substation (approximately 22.6 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Tenaja Substation (approximately 5 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Stadler Substation (approximately 2.6 miles)

In total, this system alternative would require the construction of approximately 30.2 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided in the subsections that follow

New 220/115 kV Substation

The SCE Orange County system alternative would involve the construction of a new, approximately 15-acre, 220/115 kV substation on a privately owned, approximately 67.3-acre, vacant parcel. The parcel is located southeast of Tenaja Road in the City of Murrieta. The parcel is generally trapezoidal in shape and surrounded by hilly, undeveloped land to the south and generally flat, undeveloped land to the north. SCE may establish vehicular access to this site from Tenaja Road, which is currently an unpaved road.

New 220 kV Double-Circuit Transmission Line

A new 220 kV double-circuit transmission line would be constructed, connecting the new 220/115 kV substation to SCE's existing San Onofre-Viejo 220 kV transmission line. This new 220 kV transmission line would begin at the existing San Onofre-Viejo 220 kV transmission line approximately 0.2 miles southwest of the intersection of East Avenida Pico and Camino la Pedriza in the City of San Clemente in Orange County. The line would leave the interconnection with the San Onofre-Viejo 220 kV transmission line on new structures to the east for approximately 3.2 miles. At this point, the new line would enter San Diego County, generally paralleling Talega Road and SDG&E's existing Escondido-Talega 220 kV transmission line for approximately 3.1 miles,[92] reaching the intersection of Talega Road and Indian Potrero Truck Trail. The line would then extend southeast, briefly crossing Cleveland National Forest, then extending east generally parallel to SDG&E's existing Escondido-Talega 220 kV transmission line for approximately 2.2 miles. The line would continue east, crossing Cleveland National Forest for approximately 5.5 miles, then turn to the northeast for approximately 1.9 miles before entering Riverside County. At this point, the line would extend generally northeast until reaching the new 220/115 kV substation site. Approximately 4.7 miles of this portion of the route would

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[92] Approximately 0.4 miles of this portion of the line would cross back into Orange County.

cross the Santa Rosa Plateau Ecological Preserve. This segment of the system alternative would total approximately 22.6 miles.

New 115 kV Single-Circuit Subtransmission Lines

New Substation to Tenaja Substation

A new 115 kV single-circuit subtransmission line would be constructed, connecting the new 220/115 kV substation to SCE's existing 115 kV Tenaja Substation. The line would begin at the proposed new substation site in the City of Murrieta and extend generally north on new structures until intersecting Tenaja Road. At this point, the line would extend northeast along Tenaja Road, Vineyard Parkway, and Lemon Street until intersecting SCE's existing Stadler-Tenaja 115 kV subtransmission line at Adams Avenue. At this point, the new 115 kV subtransmission line and Stadler-Tenaja 115 kV subtransmission line would be co-located on a single set of structures until reaching SCE's existing 115 kV Tenaja Substation. The existing line travels generally northwest along Adams Avenue, southwest on Nutmeg Street, and then continues in a northwest direction along Washington Avenue. At the end of Washington Avenue, the route enters the City of Wildomar and continues northwest along Palomar Street until reaching Clinton Keith Road. At the intersection with Clinton Keith Road, the route travels south until terminating at SCE's existing 115 kV Tenaja Substation. This segment of the system alternative would be approximately 5 miles in length.

New Substation to Stadler Substation

A new 115 kV single-circuit subtransmission line would be constructed, connecting the new 220/115 kV substation site to SCE's existing 115 kV Stadler Substation. The line would begin at the proposed new substation site in the City of Murrieta and extend northeast for approximately 0.1 miles on new structures. At this point, the line would extend southeast, crossing the Santa Rosa Plateau Ecological Preserve for approximately 0.6 mile. The line would extend northeast, leaving the Santa Rosa Plateau Ecological Preserve, and paralleling Ivy Street until the intersection with Jefferson Avenue. At this intersection, the new 115 kV subtransmission line would be co-located on a single set of structures with SCE's existing Stadler-Tenaja 115 kV subtransmission line for approximately 0.2 miles along Los Alamos Road until terminating at SCE's existing 115 kV Stadler Substation. This segment of the system alternative would be approximately 2.6 miles in length.

C.3.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-6 on the following page.

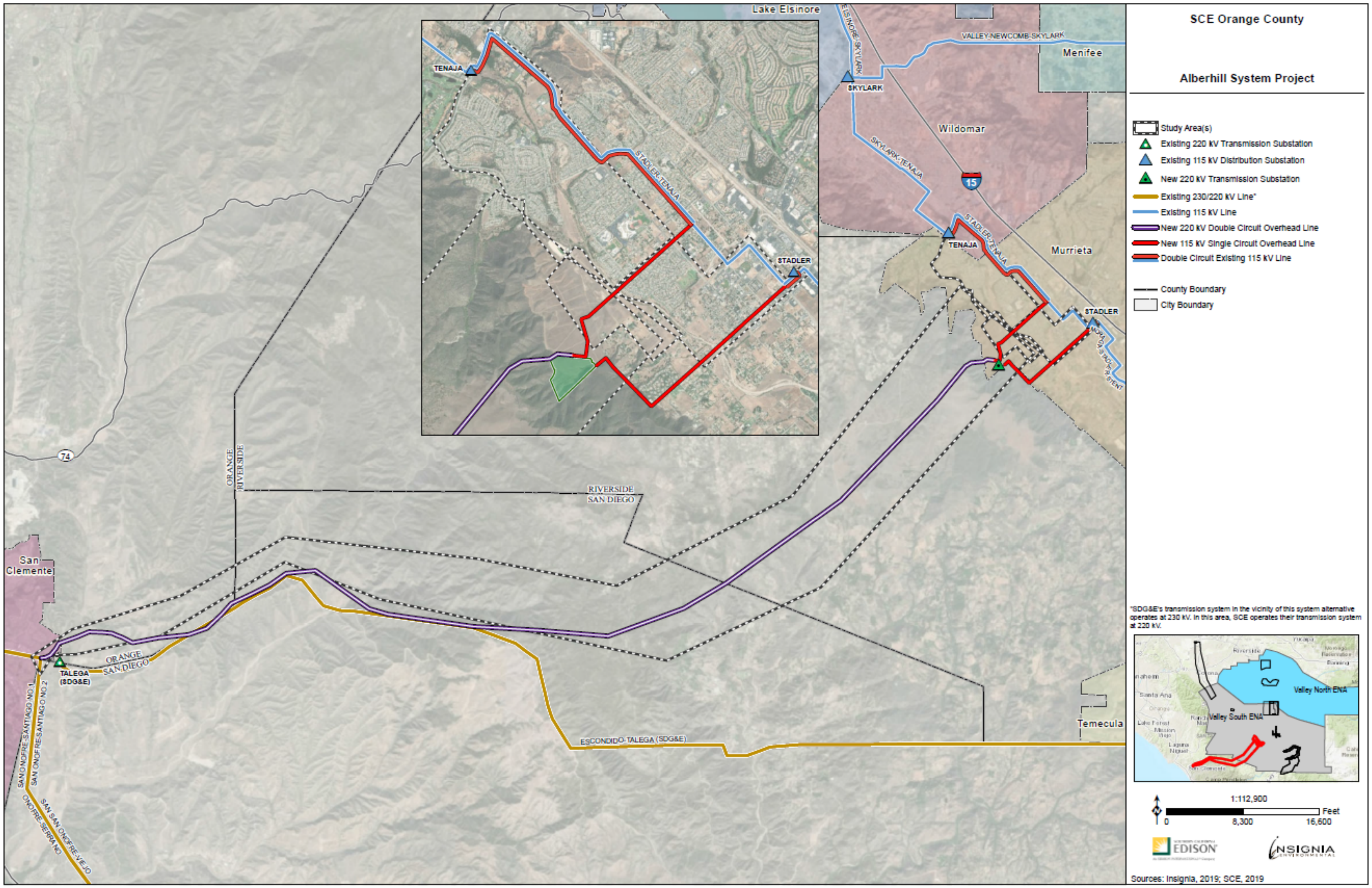


Figure C-6. Siting and Routing Map for the SCE Orange County Alternative

C.3.5 **Project Implementation Scope**

Table C-5 summarizes the scope for this alternative.

Table C-5. SCE Orange County Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 220/115 kV Station	
Electrical	New (3) position, (4) element 220 kV breaker-and-a-half switchrack to accommodate (2) transformers & (2) lines
	(2) 280 MVA, 220/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	220 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 220 kV Transmission Line	
Loop-in SONGS-Viejo 220 kV Line to New 220/115 kV Substation	22.6 miles overhead double-circuit
New 115 kV Subtransmission Lines	
New 220/115 kV Substation to Stadler Substation	2.6 miles (2.4 overhead single-circuit, 0.2 overhead double-circuit existing)
New 220/115 kV Substation to Tenaja Substation	5 miles (1.8 overhead single-circuit, 3.1 overhead double-circuit existing)
Support Scope Elements	
Substation Upgrades	
SONGS	(1) 220 kV line protection upgrade
Stadler	Remove No. 5 cap bank and convert to (1) 115 kV line position
Viejo	(1) 220 kV line protection upgrade
Tenaja	Equip (1) 115 kV Position
Distribution	
Station Light & Power – New Single-Circuit Underground	Approximately 4,800 feet
Replace Existing Double-Circuit Underbuild	Approximately 16,800 feet
Replace Existing Single-Circuit Overhead	Approximately 7,400 feet
Replace Existing Double-Circuit Overhead	Approximately 4,000 feet
Transmission Telecom	
SONGS Viejo to New 220/115 kV Sub	22.6 miles overhead fiber optic cable
New Substation to Stadler Substation	2.6 miles overhead fiber optic cable
New Substation to Tenaja Substation	5 miles overhead fiber optic cable

Scope	Detailed Scope Element
Real Properties	
Orange County Substation	Fee Acquisition – (1) 66.33-Acre Parcel
SONGS-Viejo 220 kV Transmission Line	New Easement – (75) Parcels (25 miles, 100 ft. wide, 303.03 acres total)
SONGS-Viejo 220 kV Transmission Line	Government Lands – (3) Parcels
Stadler 115 kV Subtransmission Line	New Easement – (10) Parcels, (0.5 miles, 30 ft. wide, 1.8 acres total)
Tenaja 115 kV Subtransmission Line	New Easement – (10) Parcels, (1.5 miles, 30 ft. wide, 5.5 acres total)
SCE OC Laydown Yards	Lease – (2) 15-Acre Parcels for 110 months
Environmental	
All new Substation/Transmission/Subtransmission Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 220/115 kV Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.3.6 **Cost Estimate Detail**

Table C-6 summarizes the costs for this alternative.

Table C-6. SCE Orange County Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	90
Substation Estimate	60
Owners Agent (10% of construction)	30
Corporate Security	3
Bulk Transmission	347
Subtransmission	25
Transmission Telecom	5
Distribution	6
IT Telecom	3
RP	63
Environmental	65
Subtotal Direct Cost	**637**
Subtotal Battery Cost	**n/a**
Uncertainty	314
Total with Uncertainty	**951**
Total Capex	**951**
PVRR	**748**

C.4 Menifee

C.4.1 **System Solution Overview**

The Menifee alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 500/115 kV system via construction of a new 500/115 kV substation and looping in the Serrano-Valley 500 kV transmission line. This alternative includes 115 kV subtransmission line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the newly formed 500/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two system-ties between the Valley South System and the newly formed 500/115 kV Menifee System. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the new system (Auld Substation) as needed.

C.4.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-7 on the following page.

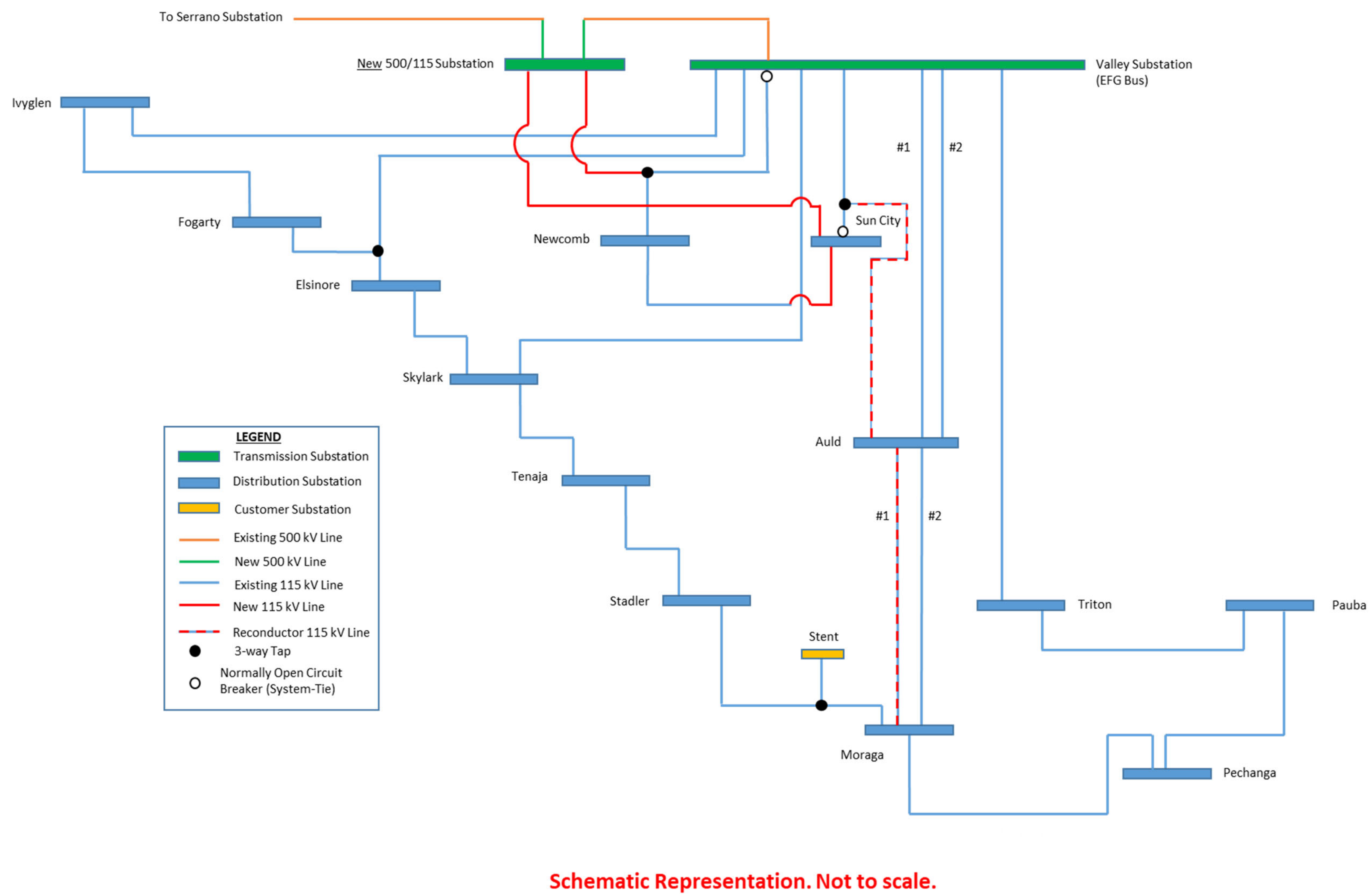


Figure C-7. System One-Line Schematic of the Menifee Alternative

C.4.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 500/115 kV substation (approximately 15-acre footprint)
- Construct a new 500 kV double-circuit transmission line to loop SCE's existing Serrano-Valley 500 kV transmission line into the new 500/115 kV substation (0.1 mile)
- Construct a new 115 kV single-circuit subtransmission line between the new 500/115 kV substation and SCE's existing 115 kV Sun City Substation (approximately 4.6 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to the new 500/115 kV substation (approximately 0.1 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Sun City 115 kV subtransmission line (approximately 7.7 miles)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)

This system alternative would require the construction of approximately 5.5 miles of new 500 kV transmission and 115 kV subtransmission lines and the modification of approximately 7.714.9 miles of existing 115 kV subtransmission line. This system alternative totals approximately 20.4 miles. A detailed description of each of these components is provided in the subsections that follow.

<u>**New 500/115 kV Substation**</u>

The Menifee system alternative would involve the construction of a new, approximately 15-acre, 500/115 kV substation on six privately owned vacant parcels, totaling approximately 23.7 acres. The parcels are located south of Matthews Road, north of McLaughlin Road, west of Palomar Road, and east of San Jacinto Road in the City of Menifee. The parcels are also located directly east of the Inland Empire Energy Center (IEEC). When combined, the parcels form a trapezoid shape and are surrounded by industrial uses and vacant lands to the north and east, SCE's existing transmission line corridor to the south, and the IEEC to the west. SCE may establish vehicular access to this site from Matthews Road, Palomar Road, and/or San Jacinto Road.

<u>**New 500 kV Double-Circuit Transmission Line**</u>

A new overhead 500 kV double-circuit transmission line segment would be constructed to loop SCE's existing Serrano-Valley 500 kV transmission line into the new 500/115 kV substation in the City of Menifee. This route would begin within SCE's existing transmission corridor along McLaughlin Road and approximately 0.1 miles west of the intersection of McLaughlin Road and

Palomar Road before extending north until reaching the new 500/115 kV substation. This segment of the system alternative would be approximately 0.1 miles in length.

New 115 kV Single-Circuit Subtransmission Lines

New Substation to Sun City Substation

A new 115 kV single-circuit subtransmission line would be constructed, connecting the new 500/115 kV substation to SCE's existing 115 kV Sun City Substation in the City of Menifee. The line would exit the new 500/115 kV substation's southeast corner and extend south along Palomar Road, crossing under SCE's existing transmission line corridor for approximately 0.3 mile. At this point, the route would extend generally southeast until reaching Rouse Road. The line would extend east along Rouse Road until the intersection with Menifee Road, then the line would transition to an underground configuration and extend south along Menifee Road for approximately 3 miles until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east for approximately 0.5 mile, parallel to the Auld-Sun City 115 kV subtransmission line, until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.6 miles in length.

Valley-Newcomb to New Substation

A new underground 115 kV subtransmission line segment would be constructed to re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to the new 500/115 kV substation in the City of Menifee. This route would begin within SCE's existing transmission corridor along McLaughlin Road, which is approximately 0.1 miles west of the intersection of McLaughlin Road and Palomar Road, and extend north until reaching the new 500/115 kV substation. This segment of the system alternative would be approximately 0.1 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld-Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet until reaching an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Reconductor Existing 115 kV Subtransmission Lines

Auld-Sun City

SCE’s existing Auld-Sun City 115 kV subtransmission line would be reconductored between SCE’s existing 115 kV Auld and Sun City Substations. This component would begin at SCE’s existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the City of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE’s existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 7.7 miles in length.

Auld-Moraga #1

SCE’s existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE’s existing 115 kV Auld and Moraga Substations. This component would begin at SCE’s existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE’s existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

C.4.4 Siting and Routing Map

A siting and routing map of this alternative is provided Figure C-8 the following page.

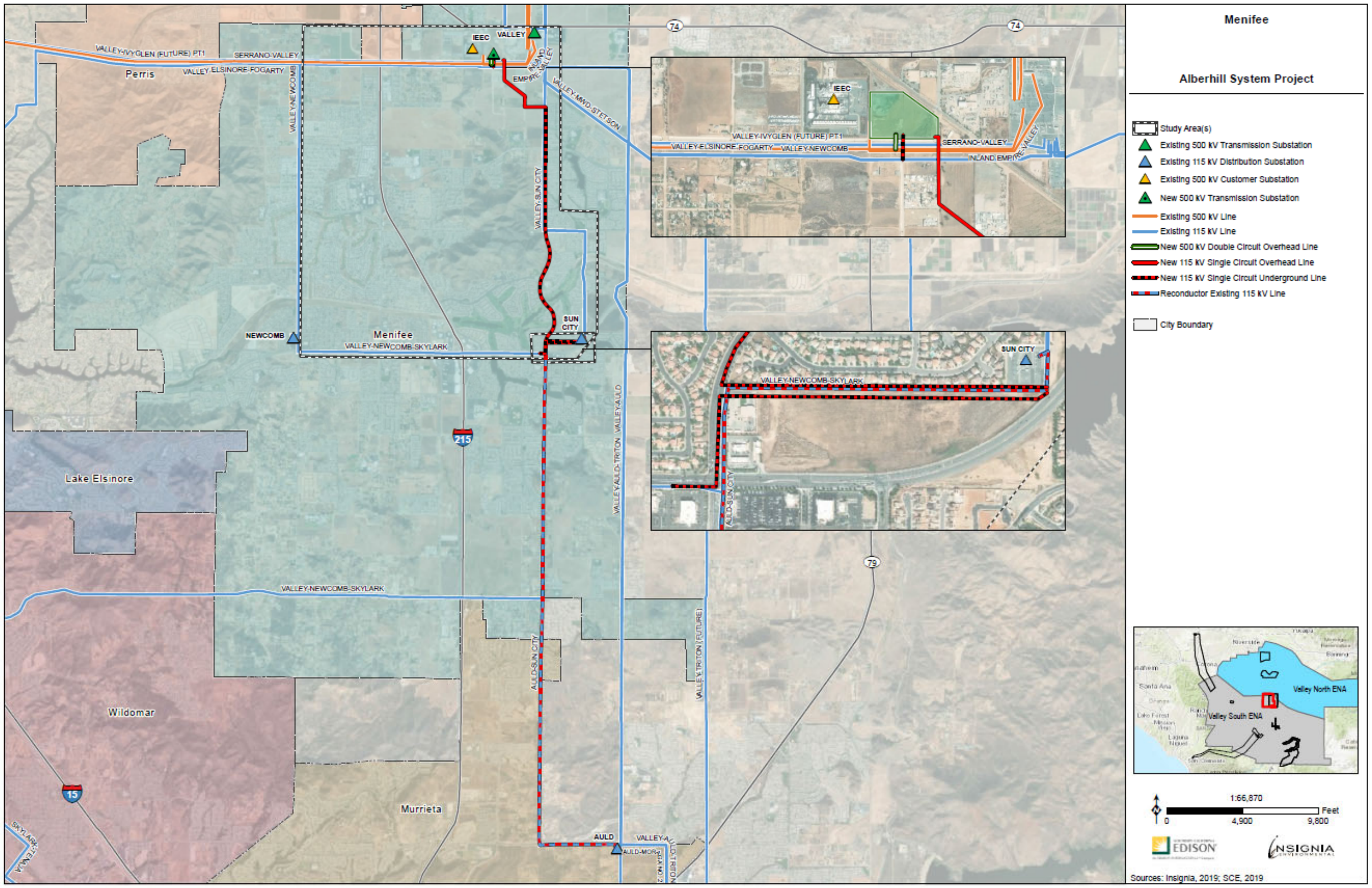


Figure C-8. Siting and Routing Map for the Menifee Alternative[93]

[93] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.4.5 Project Implementation Scope

Table C-7 summarizes the scope for this alternative.

Table C-7. Menifee Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 500/115 kV Substation	
Electrical	New (3) position, (4) element 500 kV breaker-and-a-half switchrack to accommodate (2) transformers and (2) lines
	(2) 280 MVA, 500/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	500 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 500 kV Transmission Line	
Loop-In of Serrano-Valley 500 kV Transmission Line to new 500/115 Substation	0.1 miles overhead double-circuit
New 115 kV Subtransmission Lines	
Menifee	4.8 miles (1.2 overhead single-circuit , 3.5 underground single-circuit)
Auld-Sun City	7.7 miles overhead reconductor existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Sun City-Newcomb	0.7 miles underground single-circuit
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Valley	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV position, repurpose position no. 2 for 115 kV line with (1) line protection upgrade, and (1) line protection upgrade
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 18,900 feet
Replace Existing Double-Circuit Overhead	1,400 feet
Transmission Telecom	
Menifee	4.8 miles (1.2 miles overhead, 3.5 miles underground) fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable

Scope	Detailed Scope Element
Real Properties	
Menifee	New Easement – (27) Parcels (1.5 miles, 30 ft. wide, 5.45 acres total)
Auld-Sun City	New Easement – (15) Parcels (2 miles, 30 ft. wide, 7.27 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 500/115 kV Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.4.6 **Cost Estimate Detail**

Table C-8 summarizes the costs for this alternative.

Table C-8. Menifee Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	105
Substation Estimate	93
Owners Agent (10% of construction)	12
Corporate Security	3
Bulk Transmission	4
Subtransmission	89
Transmission Telecom	3
Distribution	2
IT Telecom	5
RP	14
Environmental	24
Subtotal Direct Cost	**279**
Subtotal Battery Cost	**n/a**
Uncertainty	117
Total with Uncertainty	**396**
Total Capex	**396**
PVRR	**331**

C.5 Mira Loma

C.5.1 **System Solution Overview**

The Mira Loma alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system via construction of a new 220/115 kV substation and looping in the Mira Loma-Chino 220 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Ivyglen and Fogarty 115/12 kV distribution substations to the new 220/115 kV system. The existing 115 kV subtransmission lines serving Ivyglen and Fogarty substations would become two system-ties between the newly formed 220/115 kV Mira Loma System and the Valley South System. The system-ties would allow for the transfer of load from the new system back to the Valley South System (either or both Ivyglen and Fogarty Substations) as well as additional load transfer from the Valley South System to the new system (Elsinore Substation) as needed.

C.5.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-9 on the following page

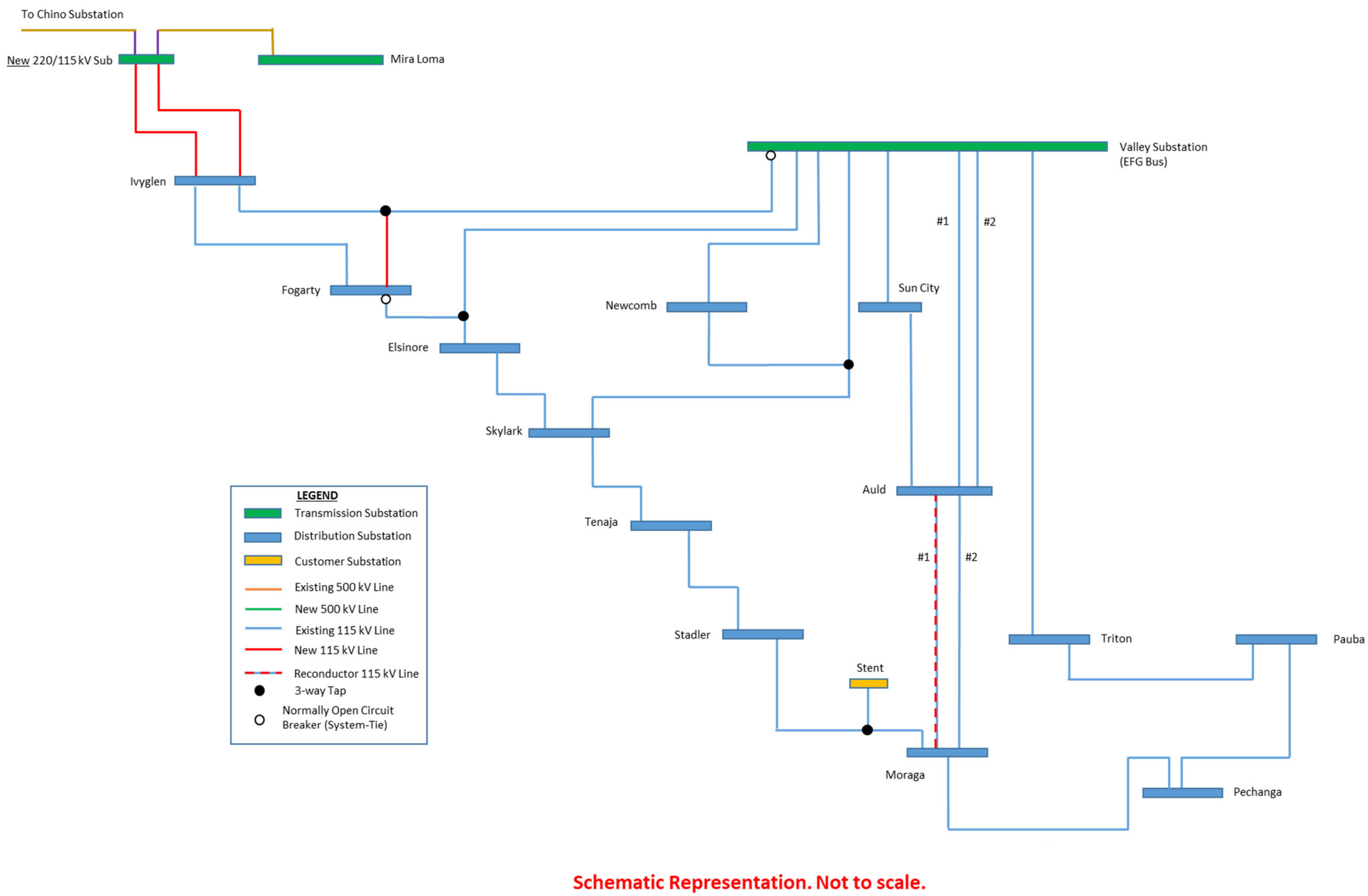


Figure C-9. System One-Line Schematic of the Mira Loma Alternative

C.5.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 220/115 kV substation (approximately 15-acre footprint)
- Construct a new 220 kV double-circuit transmission line segment to loop SCE's existing Chino-Mira Loma 220 kV transmission line into SCE's new 220/115 kV substation (approximately 130 feet)
- Construct a new 115 kV double-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation (approximately 21.6 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to tap SCE's future Valley-Ivyglen 115 kV subtransmission line to SCE's existing 115 kV Fogarty Substation (approximately 0.6 mile)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)

In total, this system alternative would require the construction of approximately 29.4 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided in the subsections that follow.

New 220/115 kV Substation

The Mira Loma system alternative would involve the construction of a new, approximately 15-acre, 220/115 kV substation on a privately owned, approximately 27-acre, vacant parcel. The parcel is located north of Ontario Ranch Road, east of Haven Avenue, and west of Hamner Avenue in the City of Ontario. The parcel is rectangular in shape and is bounded by vacant land to the north, SCE's existing 220 kV Mira Loma Substation and vacant land to the east, vacant land to the south, and vacant land and industrial uses to the west. The vacant parcel has a residential land use designation, and an existing SCE transmission corridor crosses the southeast portion of the site. Vehicular access would likely be established from Ontario Ranch Road.

New 220 kV Double-Circuit Transmission Line

A new 220 kV double-circuit transmission line segment would be constructed between the existing Chino-Mira Loma 220 kV transmission line and SCE's new 220/115 kV substation. This approximately 130-foot segment would begin within SCE's existing transmission corridor and approximately 2,000 feet east of Haven Avenue and would extend south until reaching SCE's new 220/115 kV substation site.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line would be constructed, connecting SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation. This line would exit the new 220/115 kV substation site from the southerly portion of the property and travel east in an underground configuration along Ontario Ranch Road for approximately 0.2 mile. The line would pass under SCE's existing transmission line corridor and then transition to an overhead configuration, continuing on new structures along Ontario Ranch Road for approximately 0.5 miles until intersecting Hamner Road. The line would then extend south along Hamner Road and parallel to SCE's existing Mira Loma-Corona 66 kV subtransmission line for approximately 6.8 miles. Within this approximately 6.8-miles portion of the route, the line would exit the City of Ontario and enter the City of Eastvale at the intersection with Bellegrave Avenue. Within the City of Eastvale, the line would continue along Hamner Avenue, cross the Santa Ana River, and enter the City of Norco. Within the City of Norco, the line would continue south along Hamner Avenue until intersecting 1st Street. At this point, the line would extend west along 1st Street for approximately 0.5 miles until West Parkridge Avenue. At this intersection, the line would enter the City of Corona and continue generally south along North Lincoln Avenue for approximately 3.2 miles, paralleling the Chase-Corona-Databank 66 kV subtransmission line between Railroad Street and West Ontario Avenue. At the intersection with West Ontario Avenue, the line would extend east and continue to parallel SCE's existing Chase-Corona-Databank 66 kV subtransmission line for approximately 1.4 miles until the intersection with Magnolia Avenue. The line would continue to extend along West Ontario Avenue for approximately 0.2 mile, then parallel SCE's existing Chase-Jefferson 66 kV subtransmission line between Kellogg Avenue and Interstate (I-) 15 for approximately 1.7 miles. The line would continue along East Ontario Avenue, pass under I-15, and exit the City of Corona after approximately 0.2 miles at the intersection of East Ontario Avenue and State Street. The line would extend southeast along East Ontario Avenue within Riverside County for approximately 1.8 miles until the intersection of Cajalco Road. At this intersection, the line would extend southeast along Temescal Canyon Road, crossing the City of Corona for approximately 1.2 miles between Cajalco Road and Dos Lagos Drive. The line would then continue within Riverside County along Temescal Canyon Road for approximately 3.9 miles, crossing under I-15 and terminating at SCE's existing 115 kV Ivyglen Substation. This segment of the system alternative would be approximately 21.6 miles in length.

New 115 kV Single-Circuit Subtransmission Line

A new 115 kV single-circuit subtransmission line segment would be constructed to tap SCE's future Valley-Ivyglen 115 kV subtransmission line into SCE's existing 115 kV Fogarty Substation. The new line segment would begin along the future Valley-Ivyglen 115 kV subtransmission line's alignment, approximately 680 feet southeast of the intersection of Pierce Street and Baker Street in the City of Lake Elsinore. The new line segment would extend generally southwest and parallel to SCE's existing Valley-Elsinore-Fogarty 115 kV subtransmission line until terminating at SCE's existing 115 kV Fogarty Substation. This segment of the system alternative would be approximately 0.6 miles in length.

Reconductor Existing 115 kV Subtransmission Lines

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

C.5.4 **Siting and Routing Map**

A siting and routing map of this alternative is provided in Figure C-10 on the following page.

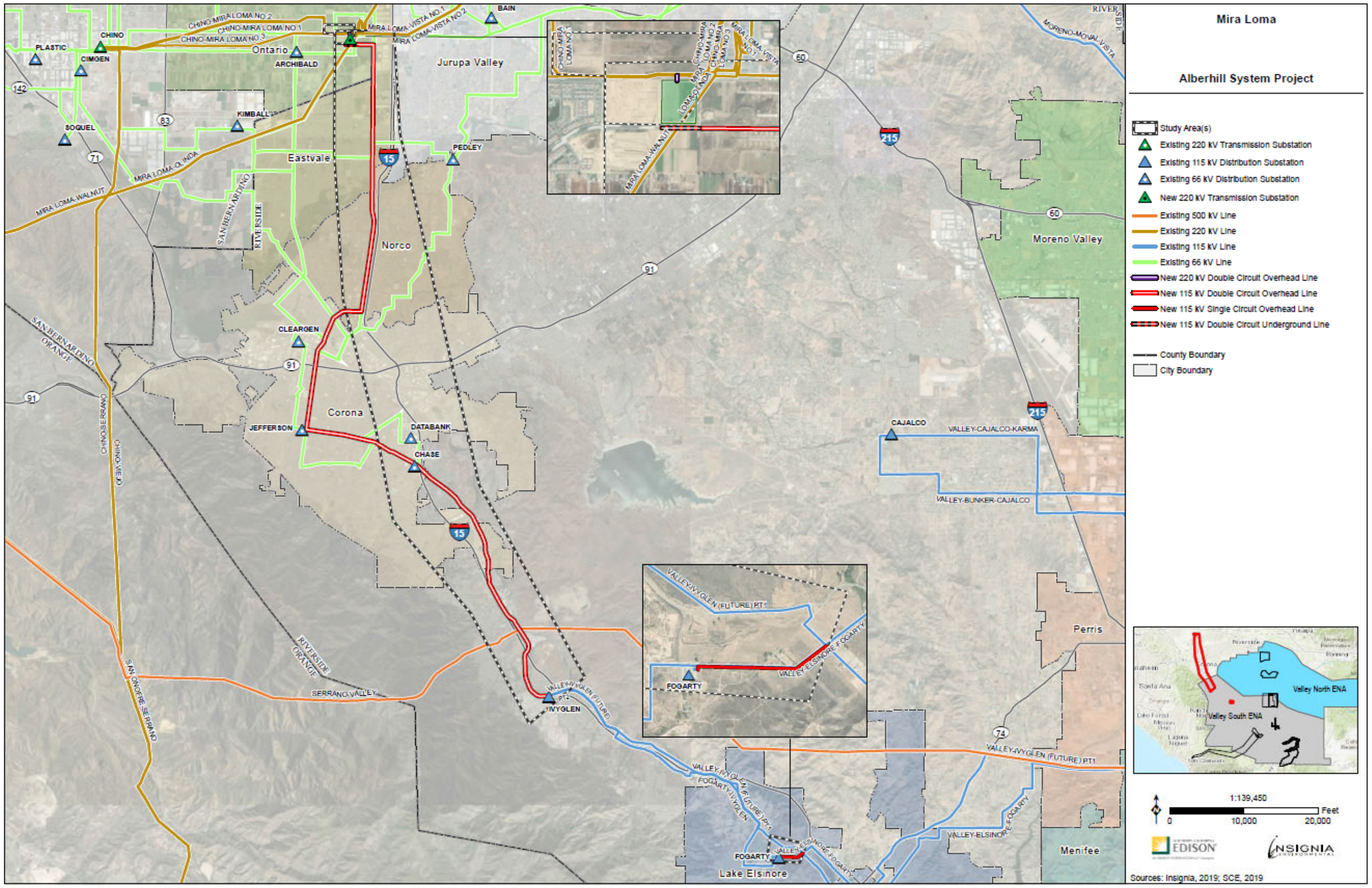


Figure C-10. Siting and Routing Map for the Mira Loma Alternative[94]

[94] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.5.5 **Project Implementation Scope**

Table C-9 summarizes the scope for this alternative.

Table C-9. Mira Loma Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 220/115 kV Station	
Electrical	New (3) position, (4) element 220 kV breaker-and-a-half switchrack to accommodate (2) transformers & (2) lines
	(2) 280 MVA, 220/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	220 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 220 kV Transmission Line	
Loop-in Chino-Mira Loma 220 kV Transmission Line to New 220/115 kV Substation	100 feet new overhead double-circuit
New 115 kV Subtransmission Lines	
Mira Loma-Ivyglen	21.6 miles (21.4 overhead double-circuit , 0.2 underground double-circuit)
Valley-Ivyglen to Fogarty	0.6 miles overhead single-circuit
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Mira Loma	(1) 220 kV line protection upgrade
Chino	(1) 220 kV line protection upgrade
Fogarty	Equip (1) 115 kV line position
Ivyglen	Remove No.3 capacitor from Position 1
	Equip (2) 115 kV line positions; (1) 115 kV line protection upgrade
Valley	(1) 115 kV line protection upgrade
Distribution	
Replace Existing Single-Circuit Overhead	Approximately 15,400 feet
Replace Existing Double-Circuit Overhead	Approximately 11,200 feet
Transmission Telecom	
Chino-Mira Loma 220 kV Line to New 220/115 Substation	100 feet overhead fiber optic cable
Mira Loma-Ivyglen	21.6 miles (21.4 overhead, 0.2 underground) fiber optic cable
Valley-Ivyglen to Fogarty	0.6 miles overhead fiber optic cable

Scope	Detailed Scope Element
Real Properties	
Mira Loma Substation D-C-02A	Fee Acquisition – (1) 26.78-Acre Parcel
Mira Loma-Ivyglen 115 kV Subtransmission Line	New Easement – (68) Parcels (10 miles, 30 ft. wide, 36.36 acres total)
Valley-Ivyglen to Fogarty 115 kV Subtransmission Line	New Easement – (10) Parcels (0.36 miles, 30 ft. wide, 1.31 acres total)
Mira Loma Laydown Yard	Lease – (1) 10-Acre Parcel for 92 months
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 220/115 kV Substation	Access Control System, Video Surveillance, Intercom System, Gating, etc.

C.5.6 **Cost Estimate Detail**

Table C-10 summarizes the costs for this alternative.

Table C-10. Mira Loma Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	64
Substation Estimate	54
Owners Agent (10% of construction)	9
Corporate Security	3
Bulk Transmission	3
Subtransmission	97
Transmission Telecom	3
Distribution	4
IT Telecom	3
RP	22
Environmental	21
Subtotal Direct Cost	**243**
Subtotal Battery Cost	**n/a**
Uncertainty	113
Total with Uncertainty	**365**
Total Capex	**365**
PVRR	**309**

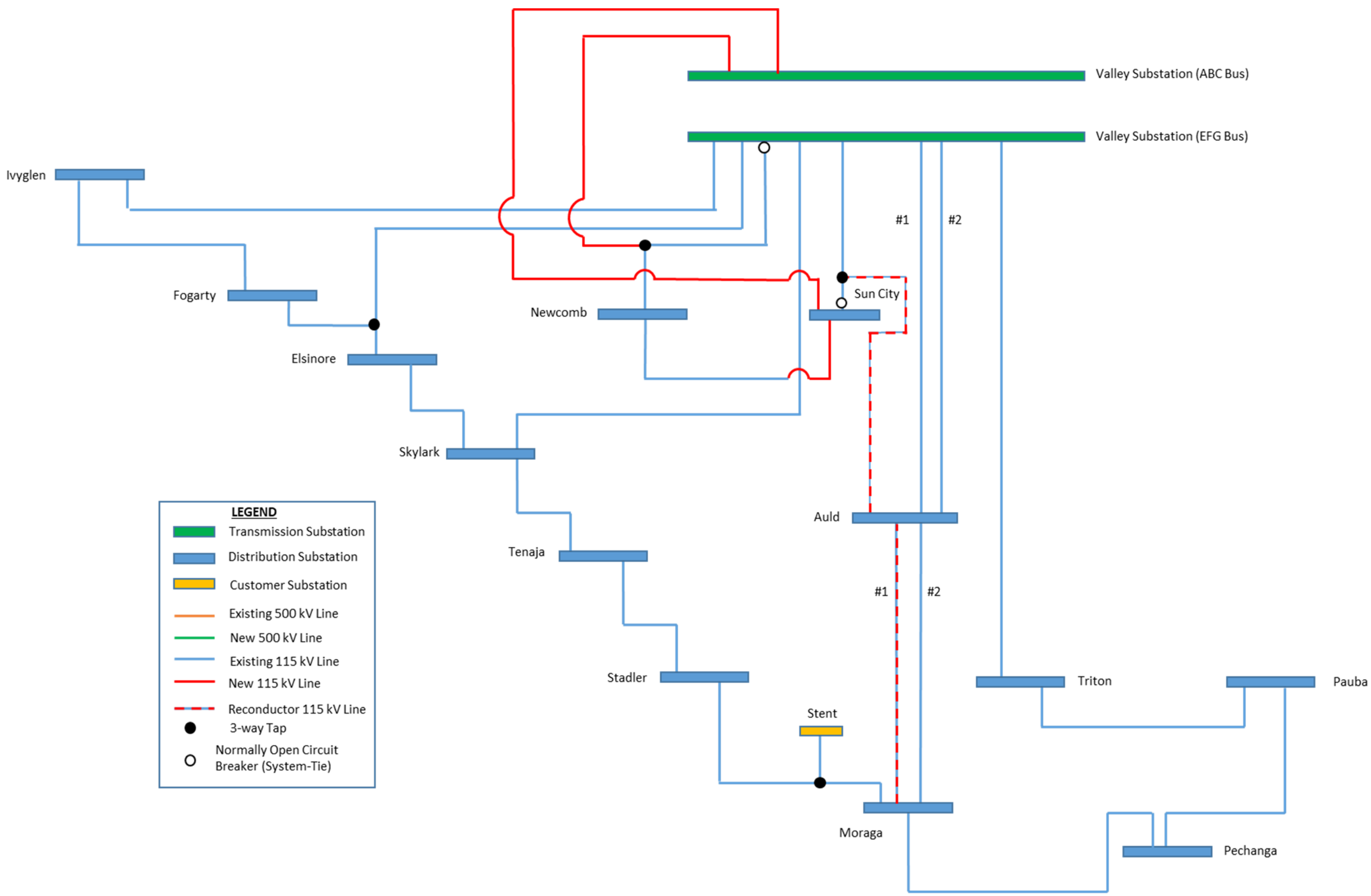
C.6 Valley South to Valley North

C.6.1 **System Solution Overview**

The Valley South to Valley North alternative proposes to transfer load away from SCE’s existing Valley South 500/115 kV System to SCE’s existing Valley North 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE’s Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed.

C.6.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-11 on the following page.



Schematic Representation. Not to scale.

Figure C-11. System One-Line Schematic of the Valley South to Valley North Alternative

C.6.3 Siting and Routing Description

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Sun City 115 kV subtransmission line (approximately 7.7 miles)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)

This system alternative would require the construction of approximately 5.9 miles of new 115 kV subtransmission line and the modification of approximately 14.9 miles of existing 115 kV subtransmission line. This system alternative totals approximately 20.8 miles. A detailed description of each of these components is provided in the subsections that follow.

<u>New 115 kV Single-Circuit Subtransmission Lines</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld-Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Reconductor Existing 115 kV Subtransmission Line

Auld-Sun City

SCE's existing Auld-Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the City of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 7.7 miles in length.

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena

Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

C.6.4 **Siting and Routing Map**

A siting and routing map of this alternative is provided in Figure C-12 on the following page.

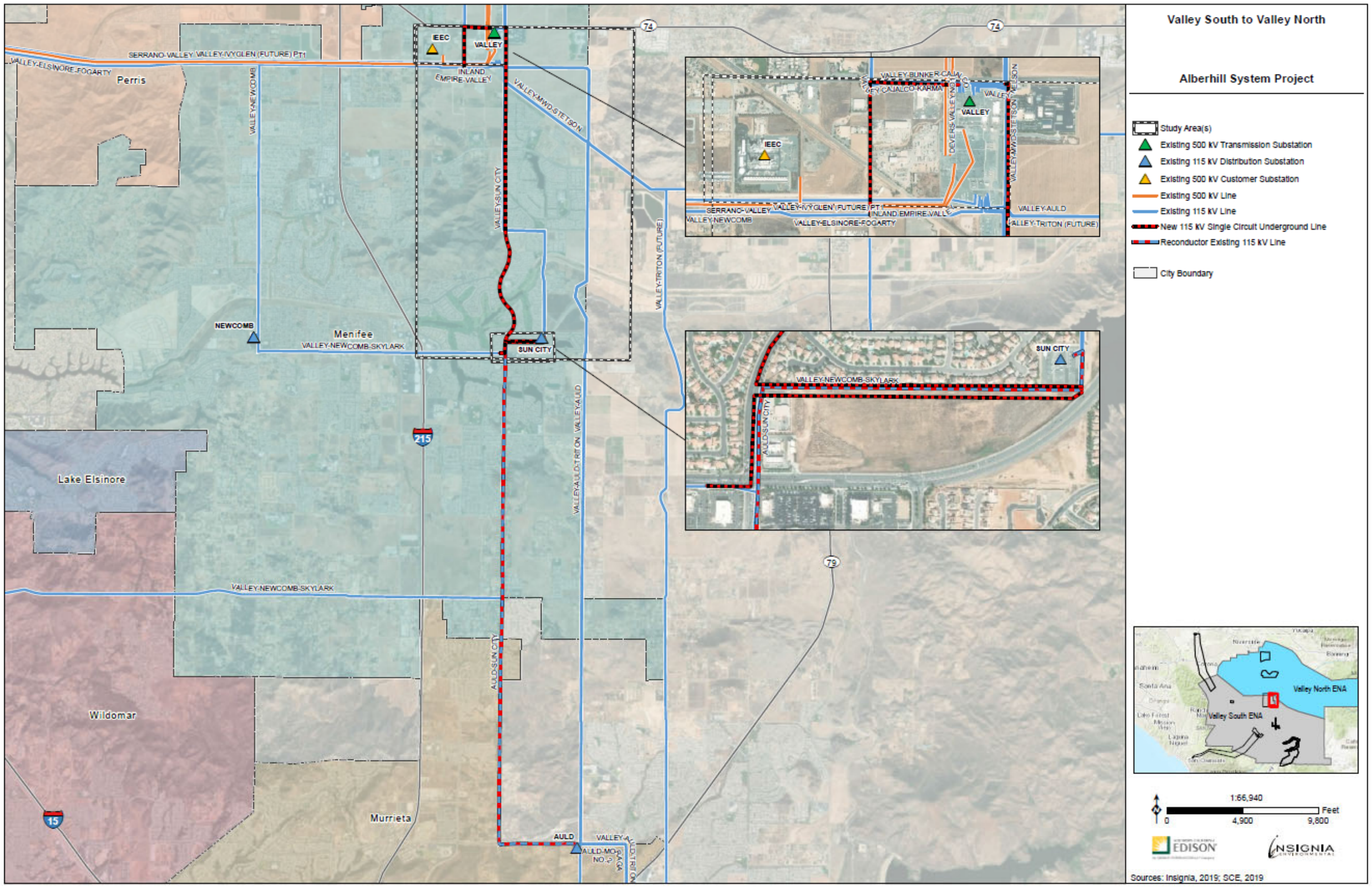


Figure C-12. Siting and Routing Map for the Valley South to Valley North Alternative[95]

95 Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.6.5 **Project Implementation Scope**

Table C-11 summarizes the scope for this alternative.

Table C-11. Valley South to Valley North Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Sun City	7.7 miles overhead reconductor existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position, repurpose position No. 2 for 115 kV line with (1) line protection upgrade, and (1) line protection upgrade
Valley	Equip 115 kV Position 7 with (2) new 115 kV Lines, and (2) line protection upgrades on Valley South switchrack.
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 18,900 feet
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Real Properties	
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Auld-Sun City	New Easement – (15) Parcels (2 miles, 30 ft. wide, 7.27 acres total)
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
N/A	N/A

C.6.6 **Cost Estimate Detail**

Table C-12 summarizes the costs for this alternative.

Table C-12. Valley South to Valley North Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	10
Substation Estimate	4
Owners Agent (10% of construction)	6
Corporate Security	n/a
Bulk Transmission	n/a
Subtransmission	100
Transmission Telecom	3
Distribution	2
IT Telecom	1
RP	6
Environmental	15
Subtotal Direct Cost	**169**
Subtotal Battery Cost	**n/a**
Uncertainty	52
Total with Uncertainty	**221**
Total Capex	**221**
PVRR	**207**

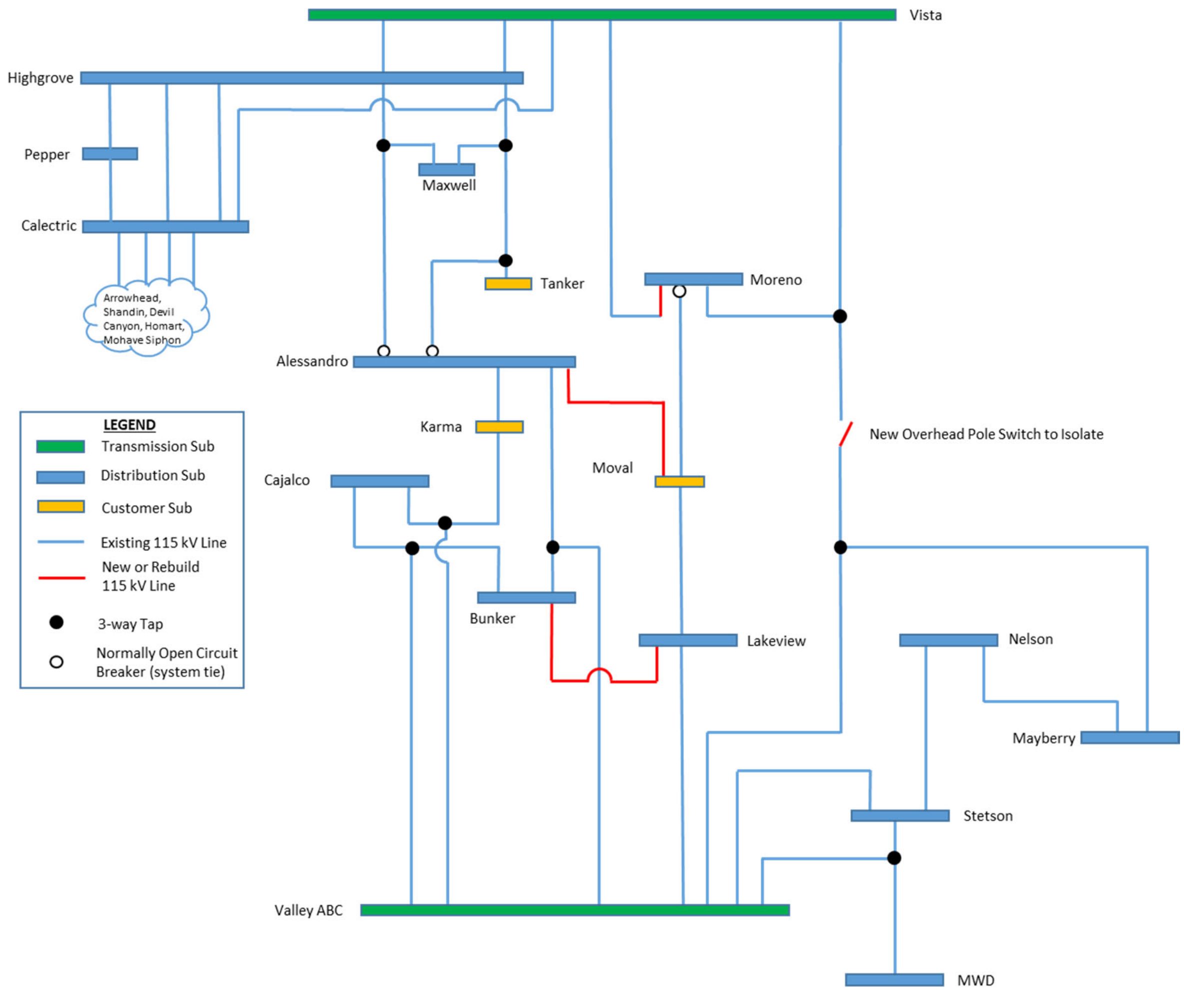
C.7 Valley South to Valley North to Vista

C.7.1 **System Solution Overview**

The Valley South to Valley North to Vista alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to the Valley North 500/115 kV System, and away from the Valley North 500/115 kV System to the Vista 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations from the Valley South to the Valley North System, and the Moreno 115/12 kV distribution substation to the Vista System. Subtransmission line construction and modifications in Valley South create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed. Subtransmission line construction and modifications in Valley North create two system-ties between the Valley North and Vista Systems. These system-tie lines would allow for the transfer of load from the Vista system back to the Valley North System (Moreno Substation) as well as additional load transfer from the Valley North System to the Vista System (Mayberry Substation) as needed.

C.7.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-13 and Figure C-14 on the following pages (Valley North portion and Valley South portion, respectively).



Schematic Representation. Not to scale.

Figure C-13. System One-Line Schematic of the Valley South to Valley North to Vista Alternative (Valley North Portion)

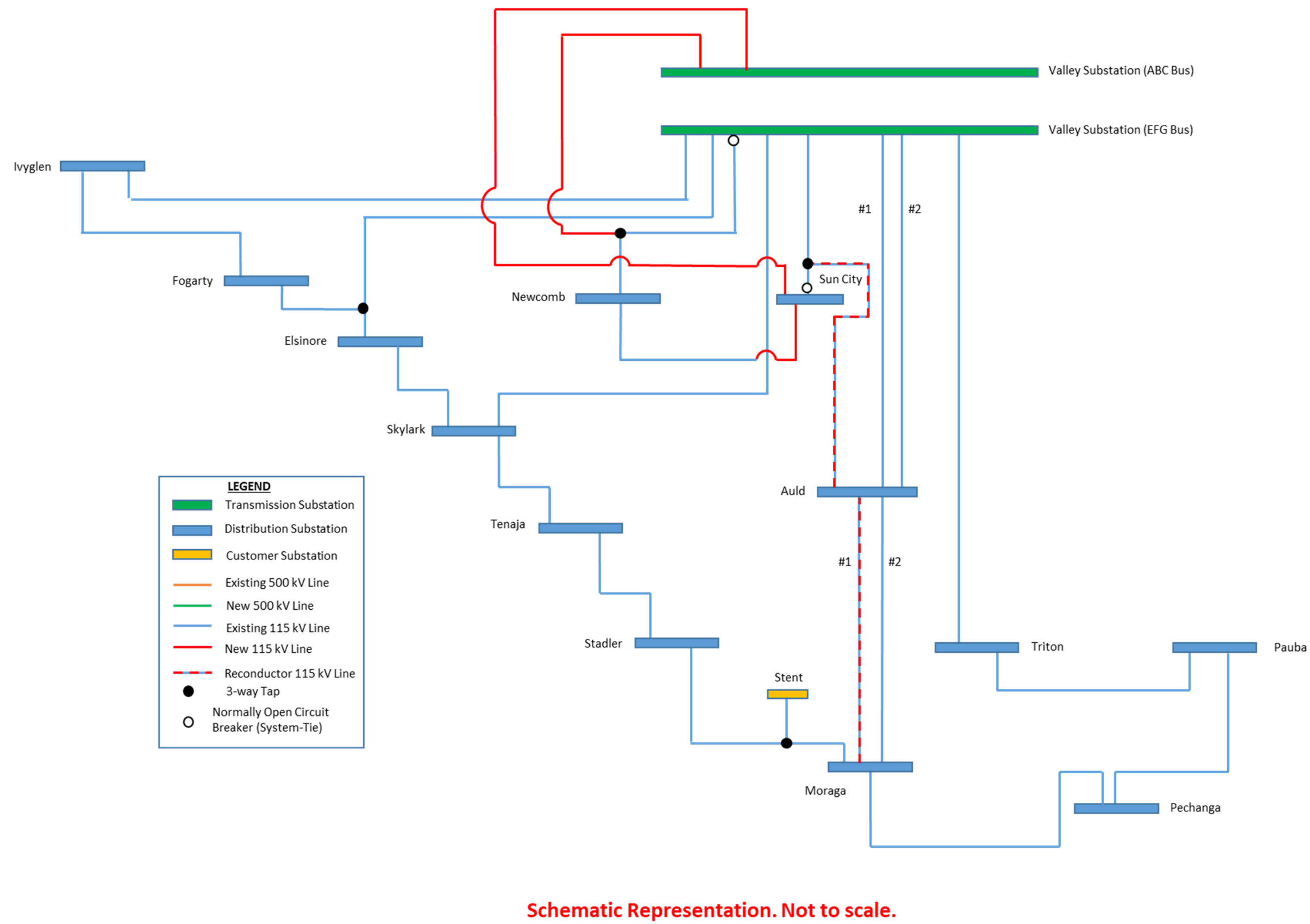


Figure C-14. System One-Line Schematic of the Valley South to Valley North to Vista Alternative (Valley South Portion)

C.7.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE’s existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE’s existing Valley-Newcomb 115 kV subtransmission line to SCE’s existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE’s existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE’s existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Construct a new 115 kV single-circuit subtransmission line between SCE’s existing 115 kV Bunker and Lakeview Substations (approximately 6 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE’s existing 115 kV Alessandro and Moval Substations (approximately 4 miles)
- Reconductor SCE’s existing, single-circuit Auld-Sun City 115 kV subtransmission line (approximately 7.7 miles)
- Reconductor SCE’s existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Double-circuit a segment of SCE’s existing 115 kV Moreno-Moval-Vista subtransmission line (approximately 0.1 mile)

This system alternative would require the construction of approximately 15.9 miles of new 115 kV subtransmission line and the modification of approximately 15 miles of existing 115 kV subtransmission line. This system alternative totals approximately 31 miles. A detailed description of each of these components is provided in the subsections that follow.

New 115 kV Single-Circuit Subtransmission Lines

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE’s existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit SCE’s existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south for approximately 3.9 miles along Menifee Road until reaching SCE’s existing Auld-Sun City 115 kV subtransmission line, which is approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east and parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE’s existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north, under SCE's existing transmission corridor, and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west and parallel to SCE's existing Auld-Sun City 115 kV subtransmission line until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Bunker Substation to Lakeview Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Bunker Substation in the City of Perris and SCE's existing 115 kV Lakeview Substation in Riverside County. From SCE's existing 115 kV Bunker Substation, the line would extend south on Wilson Avenue on new structures for approximately 0.4 miles until the intersection with Placentia Avenue. At this intersection, the line would extend east on Placentia Avenue for approximately 0.4 mile, then turn south for approximately 0.3 miles and travel parallel to a dry creek bed until the intersection with Water Avenue. At the intersection with Water Avenue, the line would leave the City of Perris, extending east for approximately 0.8 miles until the intersection with Bradley Road. The line would then continue east across vacant and agricultural lands for approximately 2.1 miles until intersecting SCE's existing Valley-Lakeview 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Valley-Lakeview 115 kV subtransmission line for approximately 2 miles, extending north until terminating at SCE's existing 115 kV Lakeview Substation. The current route extends north, southeast along 11th Street, and northeast along an unpaved access road before arriving at SCE's existing 115 kV Lakeview Substation. This segment of the system alternative would be approximately 6 miles in length.

Alessandro Substation to Moval Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Alessandro and Moval Substations in the City of Moreno Valley. The new line would exit SCE's existing 115 kV Alessandro Substation in an underground configuration and extend north for approximately 350 feet along Kitching Street until intersecting John F Kennedy Drive. At this intersection, the line would transition to an overhead configuration on new structures and extend east along John F Kennedy Drive for approximately 0.5 miles until the intersection with Lasselle Street. The line would then extend north on Lasselle Street for approximately 1 mile until the intersection with Alessandro Boulevard, where the line would extend east for approximately 2 miles until intersecting Moreno Beach Drive and SCE's existing Lakeview-Moval 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Lakeview-Moval 115 kV subtransmission line for approximately 0.5 miles until terminating at SCE's existing 115 kV Moval Substation. The current route extends north along Moreno Beach Drive until reaching SCE's existing 115 kV Moval Substation, approximately 0.1 miles south of the intersection of Moreno Beach Drive and Cottonwood Avenue. This segment of the system alternative would be approximately 4 miles in length.

Reconductor Existing 115 kV Subtransmission Line

Auld-Sun City

SCE's existing Auld-Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the City of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 7.7 miles in length.

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for

approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

Double-Circuit Existing 115 kV Subtransmission Lines

SCE currently operates an existing, single-circuit Moreno-Moval-Vista 115 kV subtransmission line between SCE's existing 115 kV Moreno, Moval, and Vista Substations. An approximately 0.1-miles segment of this line within the City of Moreno Valley would be converted from a single-circuit to double-circuit configuration. This segment would begin at the intersection of Ironwood Avenue and Pettit Street and extend east before turning north and entering SCE's existing 115 kV Moreno Substation.

C.7.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-15 on the following page.

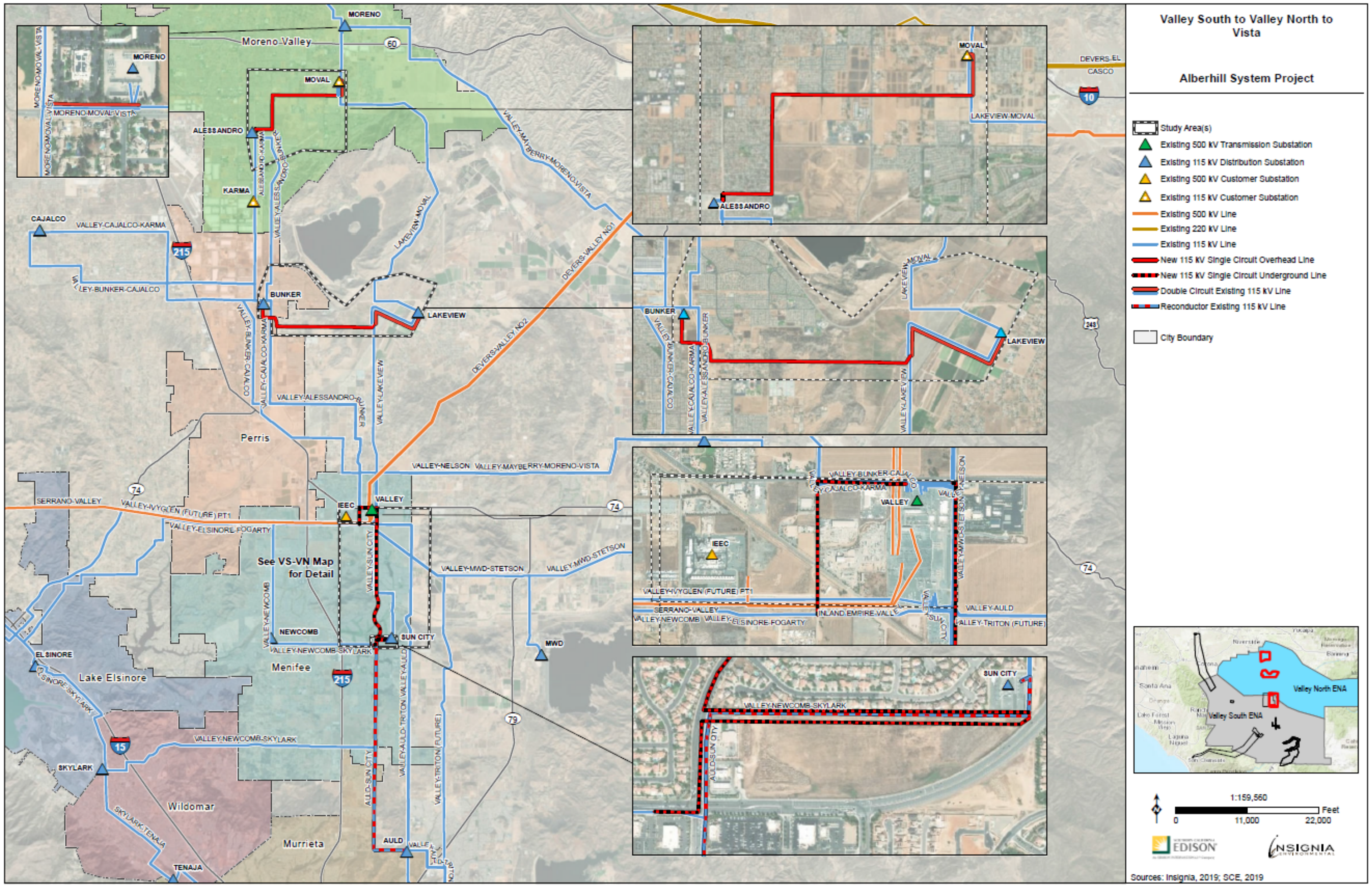


Figure C-15. Siting and Routing Map for the Valley South to Valley North to Vista Alternative[96]

[96] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.7.5 **Project Implementation Scope**

Table C-13 summarizes the scope for this alternative.

Table C-13. Valley South to Valley North to Vista Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Sun City	7.7 miles overhead reconductor existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Alessandro-Moval	4 miles (3.5 overhead single-circuit , 0.1 underground single-circuit , and 0.4 overhead double-circuit existing)
Bunker-Lakeview	6 miles (3.9 overhead single-circuit , 2.1 overhead double-circuit existing)
Moreno-Moval	0.1 miles overhead double-circuit existing
Vista-Valley-Mayberry	Install (1) 115 kV pole switch
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position , repurpose Position No. 2 for 115 kV line with (1) line protection upgrade, and (1) line protection upgrade
Valley North (ABC)	Equip 115 kV Position 7 with (2) new 115 kV lines, and (2) line protection upgrades on Valley North (ABC) switchrack
Moreno	(1) 115 kV line position
Moval	(2) 115 kV line position and (1) line protection upgrade
Bunker	Equip (1) 115 kV line position
Lakeview	Equip (1) 115 kV line position
Alessandro	Build and equip (1) 115 kV line position
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 19,200 feet
Replace Existing Single-Circuit Overhead	Approximately 12,800 feet
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Alessandro-Moval	4 miles (3.9 overhead, 0.1 underground) fiber optic cable
Bunker-Lakeview	6. miles overhead fiber optic cable

Scope	Detailed Scope Element
Moreno-Moval	0.1 miles overhead fiber optic cable
Real Properties	
Alessandro-Moval	New Easement – (20) Parcels (1 mile, 30 ft. wide, 9.09 acres total)
Bunker-Lakeview	New Easement – (45) Parcels (5 miles, 30 ft. wide, 18.18 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Auld-Sun City	New Easement – (15) Parcels (2 miles, 30 ft. wide, 7.27 acres total)
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
N/A	N/A

C.7.6 **Cost Estimate Detail**

Table C-14 summarizes the costs for this alternative.

Table C-14. Valley South to Valley North to Vista Cost Table

Project Element	Cost ($M)
Licensing	31
Substation	17
Substation Estimate	8
Owners Agent (10% of construction)	9
Corporate Security	n/a
Bulk Transmission	n/a
Subtransmission	132
Transmission Telecom	4
Distribution	3
IT Telecom	2
RP	19
Environmental	28
Subtotal Direct Cost	**238**
Subtotal Battery Cost	**n/a**
Uncertainty	79
Total with Uncertainty	**317**
Total Capex	**317**
PVRR	**290**

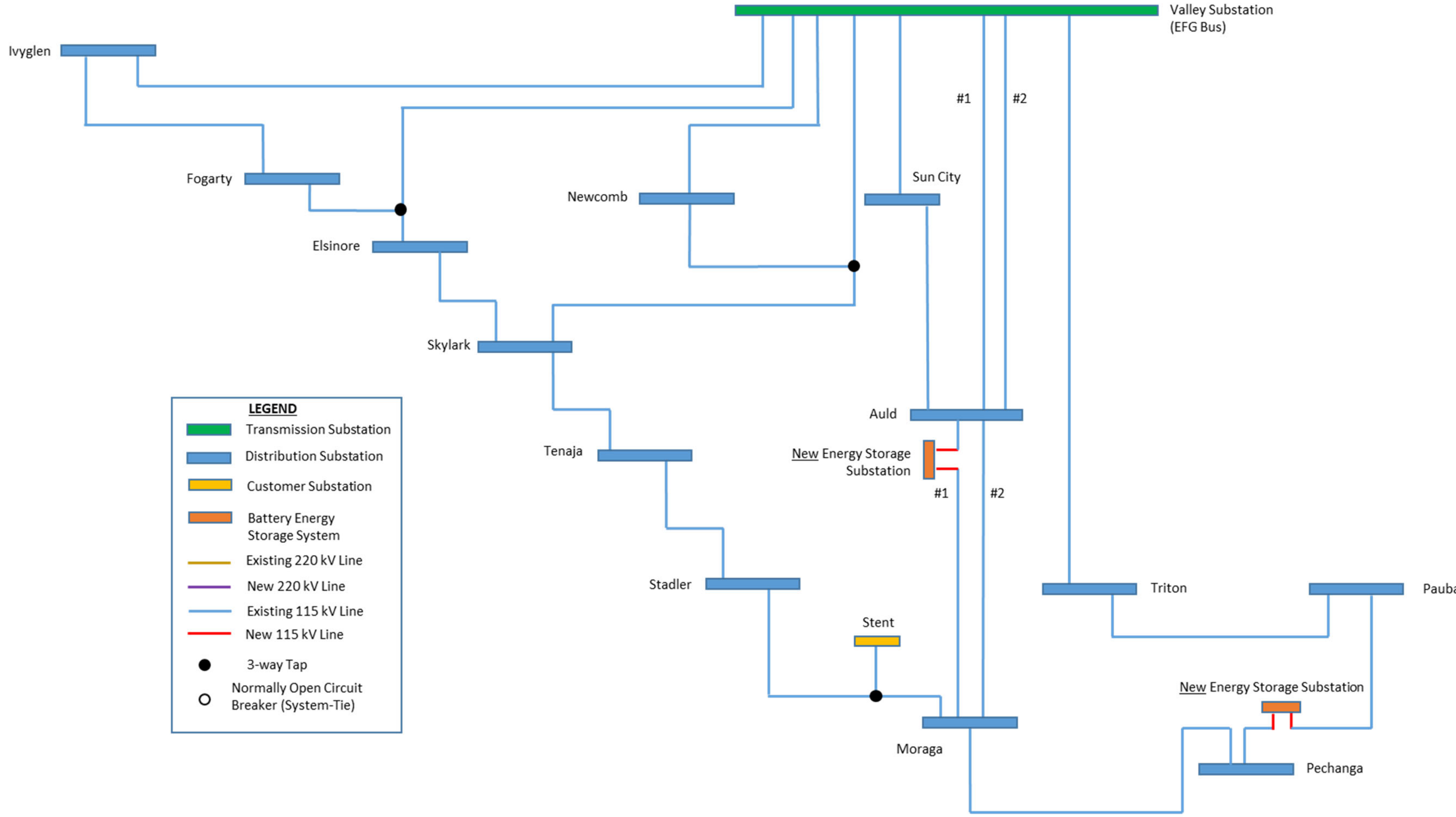
C.8 Centralized BESS in Valley South

C.8.1 **System Solution Overview**

The Centralized Battery Energy Storage System (BESS) in Valley South alternative proposes to reduce peak demand in the Valley South 500/115 kV System via construction of two new 115/12 kV substations with BESSs near Pechanga and Auld Substations, which would loop-in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.

C.8.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-16 on the following page.



Schematic Representation. Not to scale.

Figure C-16. System One-Line Schematic for the Centralized BESS in Valley South Alternative

C.8.3 Siting and Routing Description

This system alternative would include the following components:

- Construct two new 115/12 kV substations with BESSs (approximately 9-acre footprint each)
- Construct two new 115 kV subtransmission segments to loop the new BESSs into the Valley South 115 kV System.

A detailed description of each of these components is provided in the subsections that follow.

BESS and 115 kV Loop-ins

Pechanga BESS and Loop-in

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the City of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line, which is directly adjacent to the site, would be looped into the 115 kV Pechanga BESS.

Auld BESS and Loop-in

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 26.4-acre, privately owned parcel in the City of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld-Moraga 115 kV subtransmission line, which is directly adjacent to the site, would be looped into the 115 kV Auld BESS.

C.8.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-17 on the following page.

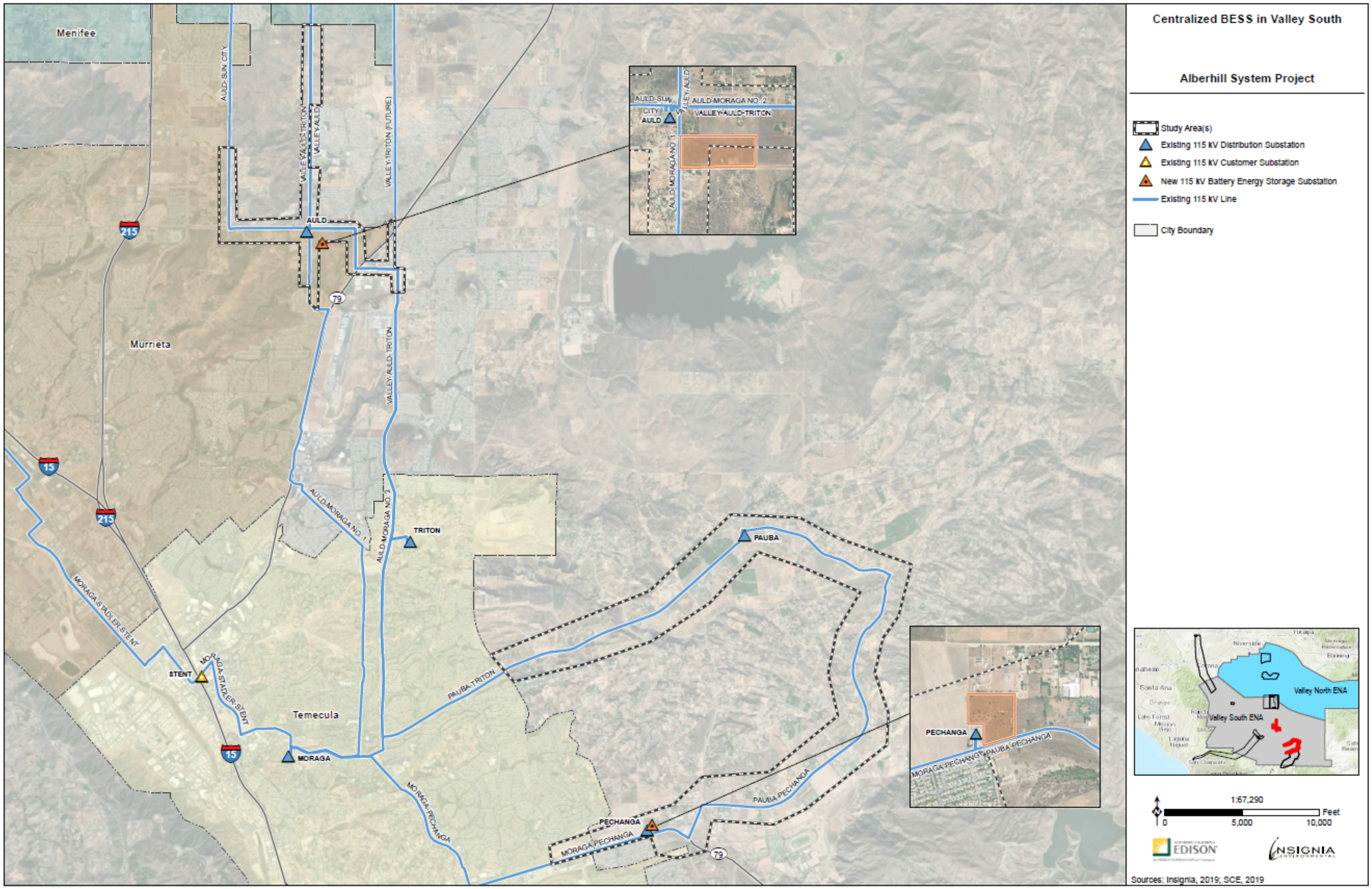


Figure C-17. Siting and Routing for the Centralized BESS in Valley South Alternative

C.8.5 Project Implementation Scope

Table C-15 summarizes the scope of this alternative.

Table C-15. Centralized BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 115/12 kV Substation with BESS (adjacent to Auld Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 115/12 kV Substation with BESS (adjacent to Pechanga Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV line protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
Support Scope Elements	
Real Properties	
Pechanga BESS Location B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
Auld BESS Location C-A-04	Fee Acquisition – (1) 24.56-Acre Parcel
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New BESS Locations	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-16 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-16. Battery Installations

Year	PVWatts Forecast		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
2022	68	216	2022	71	216	2021	110	433
2027	5	31	2027	47	281	2026	64	436
2032	46	237	2032	57	377	2031	64	506
2027	45	286	2027	52	417	2036	61	485
2042	38	299	2042	46	375	2041	54	491
						2046	18	191
Total	202	1069	Total	273	1666	Total	371	2542

C.8.6 **Cost Estimate Detail**

Table C-17 summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-17. Centralized BESS in Valley South Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	55	91	102
Substation Estimate	52	86	96
Owners Agent (10% of construction)	3	5	6
Corporate Security	3	3	3
Bulk Transmission	n/a	n/a	n/a
Subtransmission	3	3	3
Transmission Telecom	n/a	n/a	n/a
Distribution	n/a	n/a	n/a
IT Telecom	1	1	1
RP	5	5	5
Environmental	13	13	13
Subtotal Direct Cost	**111**	**147**	**158**
Subtotal Battery Cost	**681**	**1,013**	**1,729**
Uncertainty	213	314	476
Total with Uncertainty	**1,004**	**1,474**	**2,363**
Total Capex	**1,004**	**1,474**	**2,363**
Battery Revenue	**75**	**110**	**173**
PVRR	**381**	**525**	**848**

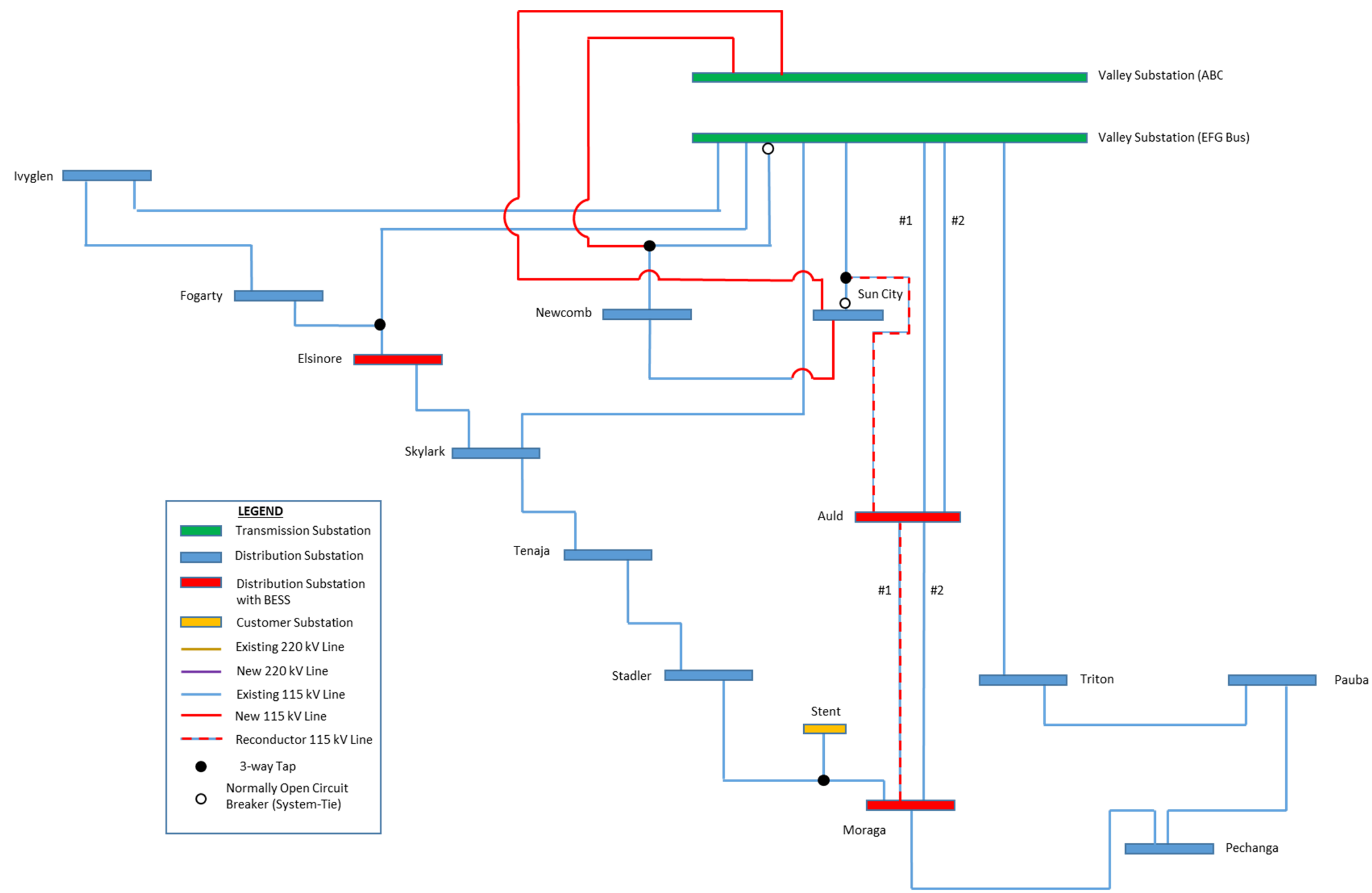
C.9 Valley South to Valley North and Distributed BESS in Valley South

C.9.1 **System Solution Overview**

The Valley South to Valley North and Distributed Battery Energy Storage System (BESS) alternative proposes to reduce peak demand in the Valley South 500/115 kV System via distributed BESSs at existing 115/12 kV distribution substations. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed.

C.9.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-18 on the following page.



Schematic Representation. Not to scale.

Figure C-18. System One-Line Schematic of the Valley South to Valley North and Distributed BESS in Valley South Alternative

C.9.3 Siting and Routing Description

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Sun City 115 kV subtransmission line (approximately 7.7 miles)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Construct new energy storage components within the existing fence lines at three existing SCE 115 kV substations

This system alternative would require the construction of approximately 5.9 miles of new 115 kV subtransmission line and the modification of approximately 14.9 miles of existing 115 kV subtransmission line. This system alternative totals approximately 20.8 miles. A detailed description of each of these components is provided in the subsections that follow.

New 115 kV Single-Circuit Subtransmission Lines

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld-Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Reconductor Existing 115 kV Subtransmission Line

Auld-Sun City

SCE's existing Auld-Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 miles until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the City of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 7.7 miles in length.

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for

approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

Energy Storage Components

This system alternative would require the installation of energy storage components within the existing fence line at three existing SCE 115 kV substations. A description of each of these substation locations is provided in the subsections that follow.

Auld Substation

SCE's existing 115 kV Auld Substation is located on approximately 4.1 acres of SCE-owned land southwest of the intersection of Los Alamos Road and Liberty Road in the City of Murrieta. This site is bounded by residential development to the south and west, and vacant land to the north and the east.

Elsinore Substation

SCE's existing 115 kV Elsinore Substation is located on approximately 2.1 acres of SCE-owned land south of the intersection of West Flint Street and North Spring Street in the City of Lake Elsinore. This site is bounded by vacant land to the west, commercial and residential uses to the north, residential uses to the east, and commercial uses to the south.

Moraga Substation

SCE's existing 115 kV Moraga Substation is located on approximately 4 acres of SCE-owned land and approximately 0.1 miles southwest of the intersection of Mira Loma Drive and Calle Violetta in the City of Temecula. This site is bounded on all sides by residential uses.

C.9.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-19 on the following page.

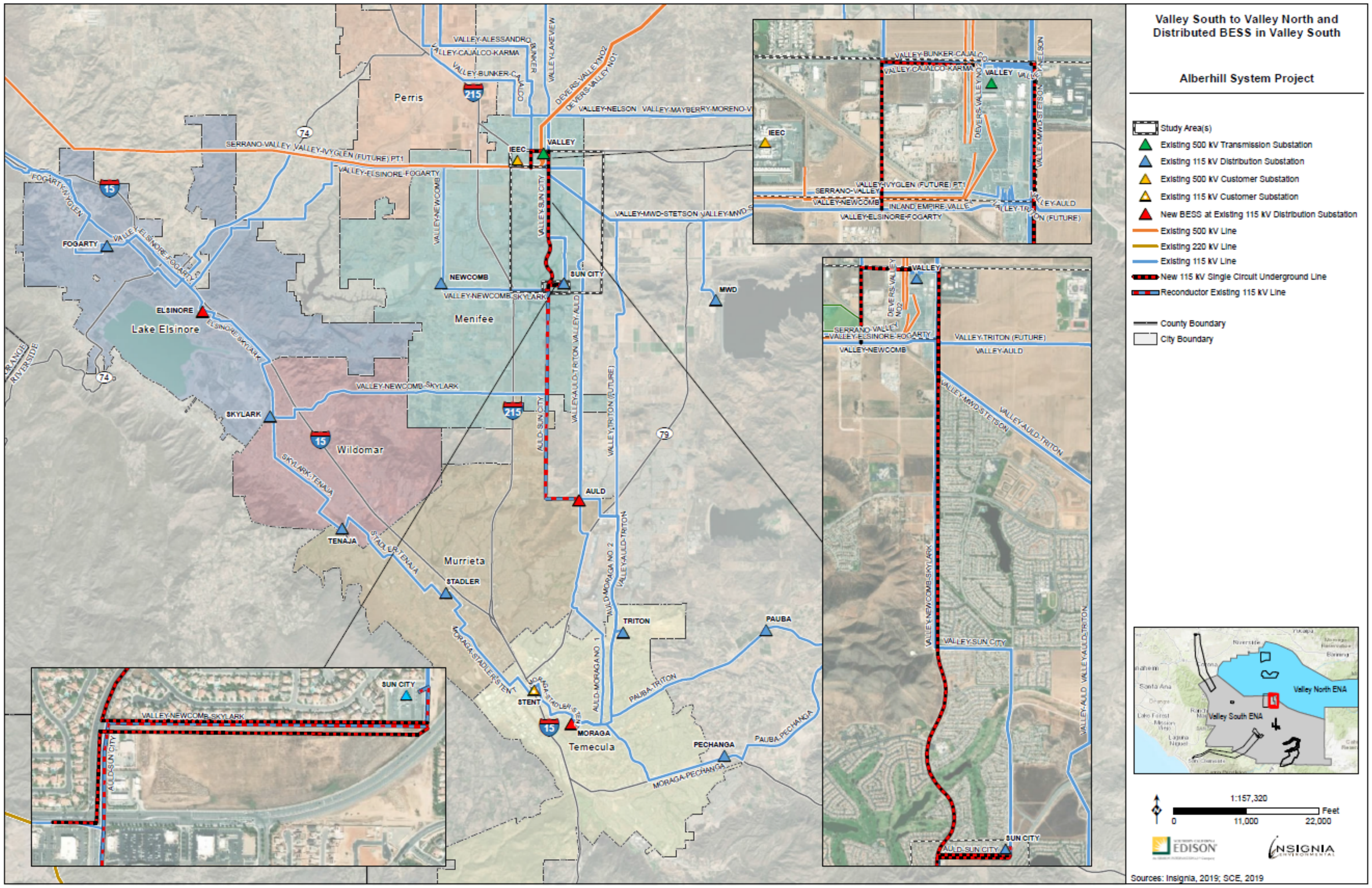


Figure C-19. Siting and Routing Map for the Valley South to Valley North and Distributed BESS in Valley South Alternative[97]

[97] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.9.5 **Project Implementation Scope**

Table C-18 summarizes the scope for this alternative.

Table C-18. Valley South to Valley North and Distributed BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
Auld Substation**	
Electrical	Equip (1) spare 12 kV position.
Batteries	10 MW/ 12 MWh
Elsinore Substation**	
Electrical	Equip (2) spare 33 kV positions.
Batteries	20 MW/ 38 MWh
Moraga**	
Electrical	Equip (2) spare 12 kV positions.
Batteries	20 MW/ 35 MWh
115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Sun City	7.7 miles overhead reconductor existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position, repurpose position No. 2 for 115 kV line with (1) line protection upgrade, and (1) line protection upgrade
Valley	Equip 115 kV Position 7 with (2) new 115 kV Lines, and (2) line protection upgrades on Valley South switchrack.
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 18,900 feet
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Real Properties	
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Auld-Sun City	New Easement – (15) Parcels

	(2 miles, 30 ft. wide, 7.27 acres total)
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
N/A	N/A

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-19 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-19. Battery Installations

Year	PVWatts Forecast1		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
-	-	-	2043	50	110	2036	50	122
Total	-	-	Total	50	110	Total	50	122

Note:

1. The PVWatts forecast does not necessitate a need for batteries to meet N-0 capacity requirements, i.e., the conventional scope of this alternative alone mitigates all N-0 transformer capacity overloads through the 30 -year horizon of the cost benefit analysis.

C.9.6 **Cost Estimate Detail**

Table C-20 summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-20. Valley South to Valley North and Distributed Battery Energy Storage System Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast[1]	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	10	13	13
Substation Estimate	4	7	7
Owners Agent (10% of construction)	6	6	6
Corporate Security	n/a	n/a	n/a
Bulk Transmission	n/a	n/a	n/a
Subtransmission	100	100	79
Transmission Telecom	3	3	3
Distribution	2	2	2
IT Telecom	1	1	1
RP	6	6	6
Environmental	15	15	15
Subtotal Direct Cost	**169**	**173**	**173**
Subtotal Battery Cost	**n/a**	**82**	**104**
Uncertainty	48	71	78
Total with Uncertainty	**218**	**326**	**354**
Total Capex	**218**	**326**	**354**
Battery Revenue	**n/a**	**2.2**	**6.4**
PVRR	**200**	**232**	**228**

Note:

1. The PVWatts forecast does not necessitate a need for batteries. The scope for this alternative under the PVWatts forecast is identical to the VS-VN alternative.

C.10 SDG&E and Centralized BESS in Valley South

C.10.1 System Solution Overview

The San Diego Gas and Electric (SDG&E) alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 230/115 kV system created at the southern boundary of the SCE service territory and adjacent to SDG&E's service territory. The new system would be provided power from the existing SDG&E 230 kV system via construction of a new 230/115 kV substation and looping in the SDG&E Escondido-Talega 230 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Pauba and Pechanga 115/12 kV distribution substations to the newly formed 230/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two 115 kV system-ties between the Valley South System and the newly formed 230/115 kV SDG&E-sourced system. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Pauba and Pechanga Substations) as well as additional load transfer from the Valley South System to the new system (Triton Substation) as needed.

To further reduce load in the Valley South System, a new 115/12 kV substation with BESS would be constructed near Auld Substation with a loop-in of the Auld-Moraga #1 line.

C.10.2 System Single Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-20 on the following page.

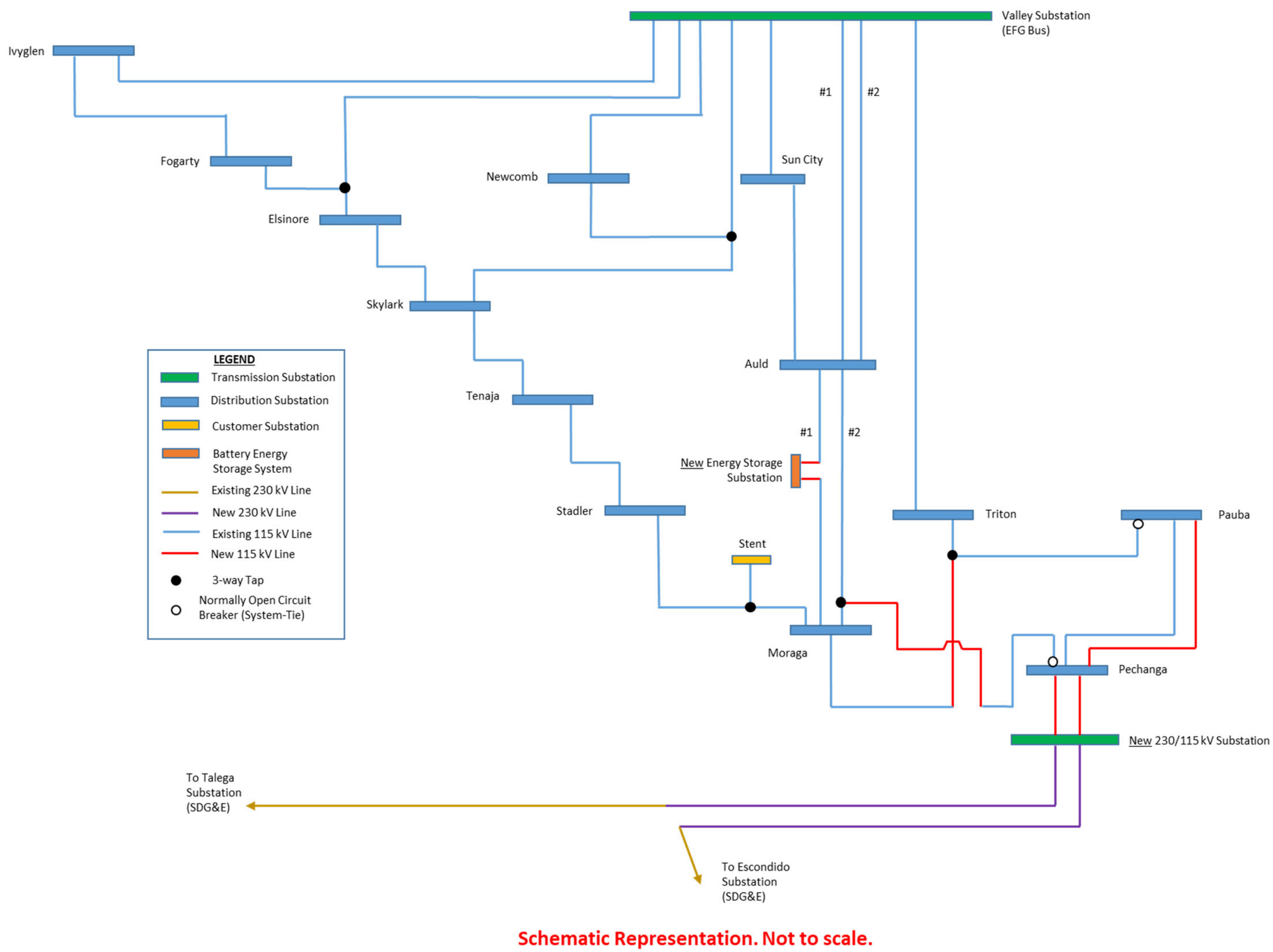


Figure C-20 System One-Line Schematic of the SDG&E and Centralized BESS in Valley South Alternative

C.10.3 Siting and Routing Description

This system alternative would include the following components:

- Construct a new 230/115 kV substation (approximately 15-acre footprint)
- Construct a new 230 kV double-circuit transmission line between SDG&E's existing Escondido-Talega 230 kV transmission line and Southern California Edison's (SCE's) new 230/115 kV substation (approximately 7.2 miles)
- Construct a new 115 kV double-circuit subtransmission line between SCE's new 230/115 kV substation and SCE's existing Pechanga Substation (approximately 2 miles)
- Demolish SCE's existing 115 kV switchrack at Pechanga Substation and reconstruct it on an adjacent parcel (approximately 3.2-acre footprint)
- Double-circuit SCE's existing Pauba-Pechanga 115 kV subtransmission line (approximately 7.5 miles)
- Double-circuit a segment of SCE's existing Auld-Moraga #2 115 kV subtransmission line (approximately 0.3 mile)
- Construct one new 115/12 kV substation with BESS (approximately 9-acre footprint)
- Construct one new 115 kV subtransmission segment to loop the new 115 kV BESS into SCE's existing 115 kV subtransmission system

This system alternative would require the construction of approximately 9.2 miles of new 230 kV transmission and 115 kV subtransmission lines and the modification of approximately 7.8 miles of existing 115 kV subtransmission line. This system alternative totals approximately 17 miles. A detailed description of each of these components is provided in the subsections that follow.

New 230/115 kV Substation

SDG&E would include the construction of a new, approximately 15-acre, 230/115 kV substation on a privately owned, approximately 56.4-acre, vacant parcel. The parcel is located north of Highway 79, between the intersections with Los Caballos Road and Pauba Road, in Riverside County. The parcel is trapezoidal in shape and is bounded by residences and equestrian facilities to the north, east, and west; and Highway 79 and vacant land to the south. SCE may establish vehicular access to the site from Los Corralitos Road or Highway 79.

New 230 kV Double-Circuit Transmission Line

A new 230 kV double-circuit transmission line would be constructed, connecting the new 230/115 kV substation to SDG&E's existing Escondido-Talega 230 kV transmission line. This new 230 kV transmission line would begin at SDG&E's existing 230 kV Escondido-Talega 230 kV transmission line approximately 0.6 miles northeast of the intersection of Rainbow Heights Road and Anderson Road in the community of Rainbow in San Diego County. The line would leave the interconnection with SDG&E's existing Escondido-Talega 230 kV transmission line on new structures extending to the northeast for approximately 0.8 mile. At this point, the new line would enter Riverside County and the Pechanga Reservation for approximately 4 miles. The line would continue in a generally northeast direction for approximately 1 miles before exiting the Pechanga Reservation and continue until intersecting Highway 79. At the intersection with Highway 79, the line would extend northwest and parallel to Highway 79 for approximately 1 miles until reaching the new 230/115 kV substation. This segment of the system alternative would be approximately 7.2 miles in length.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line would be constructed to connect the new 230/115 kV substation to SCE's existing 115 kV Pechanga Substation. The line would depart the new 230/115 kV substation to the northwest on new structures for approximately 1.5 miles while traveling parallel to Highway 79. Near the intersection of Highway 79 and Anza Road, the line would transition to an underground configuration and continue along Highway 79 for approximately 0.5 miles until reaching SCE's existing 115 kV Pechanga Substation. This segment of the system alternative would be approximately 2 miles in length.

Demolish and Reconstruct an Existing 115 kV Switchrack

SCE currently operates the existing 115 kV Pechanga Substation, located on an approximately 3.2-acre, SCE-owned parcel approximately 0.2 miles northeast of the intersection of Highway 79 and Horizon View Street. This site is bounded by vacant land to the east and west and residential uses to the north and south. SCE would demolish this existing 115 kV switchrack and reconstruct it on an approximately 16.9-acre, privately owned parcel directly east of the existing substation. The new 115 kV switchrack would occupy approximately 3.2 acres within the parcel.

Double-Circuit Existing 115 kV Subtransmission Lines

Pauba-Pechanga

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Pauba and Pechanga Substations in Riverside County. This existing line would be converted to a double-circuit configuration, adding a new 115 kV circuit between SCE's existing 115 kV Pauba and Pechanga Substations. The existing line departs SCE's existing 115 kV Pechanga Substation and extends east along Highway 79 until reaching Anza Road. At the intersection of Highway 79 and Anza Road, the line extends northeast along Anza Road until reaching De Portola Road. At this intersection, the line extends generally northeast along De Portola Road until intersecting Monte de Oro Road, then the line extends west along Monte de Oro Road until reaching Rancho California Road. At this point, the line extends south along Rancho California Road and terminates at SCE's existing 115 kV Pauba Substation. This segment of the system alternative is approximately 7.5 miles in length.

Auld-Moraga #2

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Auld Substation in the City of Murrieta and SCE's existing 115 kV Moraga Substation in the City of Temecula. An approximately 0.3-miles segment of this line within the City of Temecula would be converted from a single-circuit to double-circuit configuration. This segment would begin near the intersection of Rancho California Road and Calle Aragon. The existing line then extends south before turning west and intersecting Margarita Road, approximately 0.2 miles northwest of Rancho Vista Road.

BESS and 115kV Loop-In

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 24.6-acre, privately owned parcel in the City of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld-Moraga 115 kV subtransmission line, which is directly adjacent to the site, would be looped into the 115 kV Auld BESS.

C.10.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-21 on the following page.

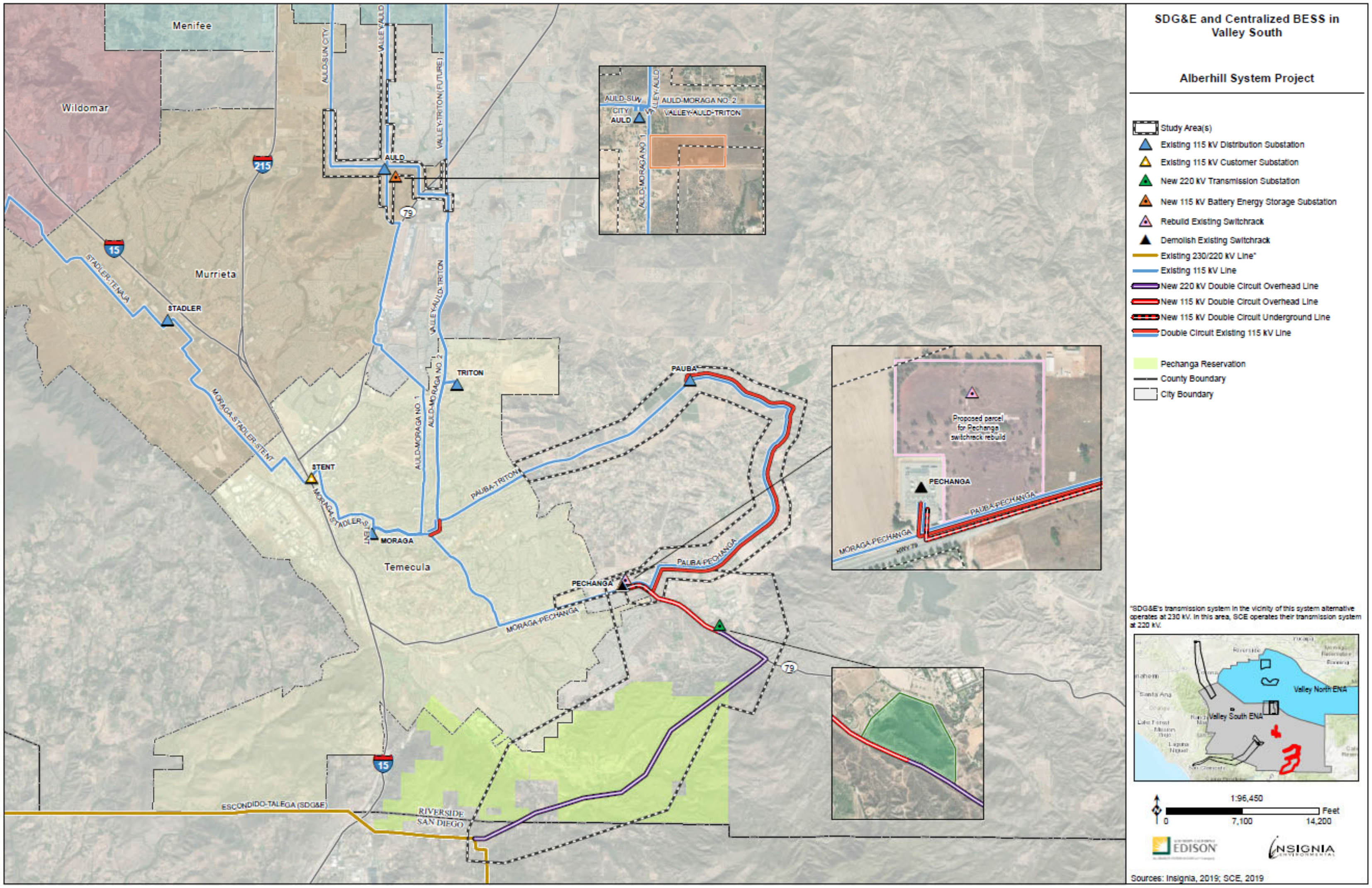


Figure C-21. Siting and Routing Map for the SDG&E and Centralized BESS in Valley South Alternative

C.10.5 **Project Implementation Scope**

Table C-21 summarizes the scope for this alternative.

Table C-21. SDG&E and Centralized BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 230/115 kV Station	
Electrical	New (3) position, (4) element 230 kV breaker-and-a-half switchrack to accommodate (2) banks & (2) lines
	(2) 280 MVA, 230/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	230 and 115 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 115/12 kV Station (adjacent to Auld Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 230 kV Transmission Line	
Loop-in SDG&E Escondido-Talega 230 kV line into New 230/115 kV Substation	7.3 miles overhead double-circuit 230 kV line
New 115 kV Subtransmission Lines	
New 230/115 kV Substation to Pechanga Substation	2 miles (1.4 overhead double-circuit, 0.6 underground double-circuit)
Pauba-Pechanga	7.5 miles overhead double-circuit existing
Moraga-Pauba-Triton	0.3 miles overhead double-circuit existing

Scope	Detailed Scope Element
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Escondido	(1) 230 kV line protection upgrade
Moraga	(1) 115 kV line protection upgrade
Pechanga	
Civil	Demo the existing 115 kV switchrack
	Extend existing perimeter fence with a guardian 5000 fence
Electrical	New (6) position, (8) element 115 kV BAAH switchrack to accommodate (3) banks & (5) lines.
	New 115 kV line protection. Replace bank protection.
	HMI upgrade.
Talega	(1) 230 kV line protection upgrade
Triton	(1) 115 kV line protection upgrade
Pauba	Equip (1) 115 kV line position and (1) 115 kV line protection upgrade
Distribution	
Station Light & Power – New Single Circuit Underground	Approximately 3,300 feet
Replace Existing Single Circuit Underbuild	Approximately 24,200 feet
Replace Existing Double Circuit Underbuild	Approximately 17,200 feet
Transmission Telecom	
SDG&E Escondido-Talega 230kV line to New 230/115 Substation	7.3 miles overhead fiber optic cable
New 230/115 kV Substation to Pechanga Substation	2 miles (1.4 miles overhead, 0.6 miles underground) fiber optic cable
Pauba-Pechanga	7.5 miles overhead fiber optic cable
Moraga-Pauba-Triton	0.3 miles overhead fiber optic cable
Real Properties	
SDG&E Substation A-A-04	Fee Acquisition – (1) 11.01-Acre Parcel
Pechanga Substation B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
SDG&E 230 kV Transmission Line	New Easement – (10) Parcels (2.5 miles, 100 ft. wide, 30.3 acres total)
SDG&E 115 kV Subtransmission Line	New Easement – (6) Parcels (2 miles, 30 ft. wide, 7.3 acres total)
Pauba-Pechanga 115 kV Subtransmission Line	New Easement – (9) Parcels (1.5 miles, 30 ft. wide, 5.5 acres total)
Auld-Moraga #2 115 kV Subtransmission Line	New Easement – (4) Parcels (0.33 miles, 30 ft. wide, 1.2 acres total)
Auld BESS Location C-A-04	Fee Acquisition – (1) 24.56-Acre Parcel
SDG&E Laydown Yards	Lease – (2) 15-Acre Parcels for 96 months
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.

Scope	Detailed Scope Element
Corporate Security	
New 230/115 kV Substation; Auld BESS Location	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-22 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-22. Battery Installations

Year	PVWatts Forecast		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
2048	20	64	2039	65	189	2033	82	262
-	-	-	2044	25	130	2038	56	323
-	-	-	-	-	-	2043	49	323
Total	20	64	Total	90	319	Total	187	908

C.10.6 **Cost Estimate Detail**

Table C-23 summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-23. SDG&E and Centralized BESS in Valley South Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	132	142	159
Substation Estimate	114	123	140
Owners Agent (10% of construction)	18	19	20
Corporate Security	4	4	4
Bulk Transmission	112	112	112
Subtransmission	43	43	43
Transmission Telecom	3	3	3
Distribution	6	6	6
IT Telecom	4	4	4
RP	23	23	23
Environmental	43	43	43
Subtotal Direct Cost	**402**	**411**	**429**
Subtotal Battery Cost	**47**	**195**	**542**
Uncertainty	237	317	503
Total with Uncertainty	**685**	**923**	**1,473**
Total Capex	**685**	**923**	**1,473**
Battery Revenue	**n/a**	**7.6**	**33**
PVRR	**479**	**531**	**658**

C.11 Mira Loma and Centralized BESS in Valley South

C.11.1 **System Solution Overview**

The Mira Loma alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system via construction of a new 220/115 kV substation and looping in the Mira Loma-Chino 220 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Ivyglen and Fogarty 115/12 kV distribution substations to the new 220/115 kV system. The existing 115 kV subtransmission lines serving Ivyglen and Fogarty substations would become two system-ties between the newly formed 220/115 kV Mira Loma System and the Valley South System. The system-ties would allow for the transfer of load from the new system back to the Valley South System (either or both Ivyglen and Fogarty Substations) as well as additional load transfer from the Valley South System to the new system (Elsinore Substation) as needed.

To further reduce load in the Valley South System, two new 115/12 kV substations with BESSs would be constructed near Pechanga and Auld Substations, which loop-in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.

C.11.2 **System Single Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-22 on the following page.

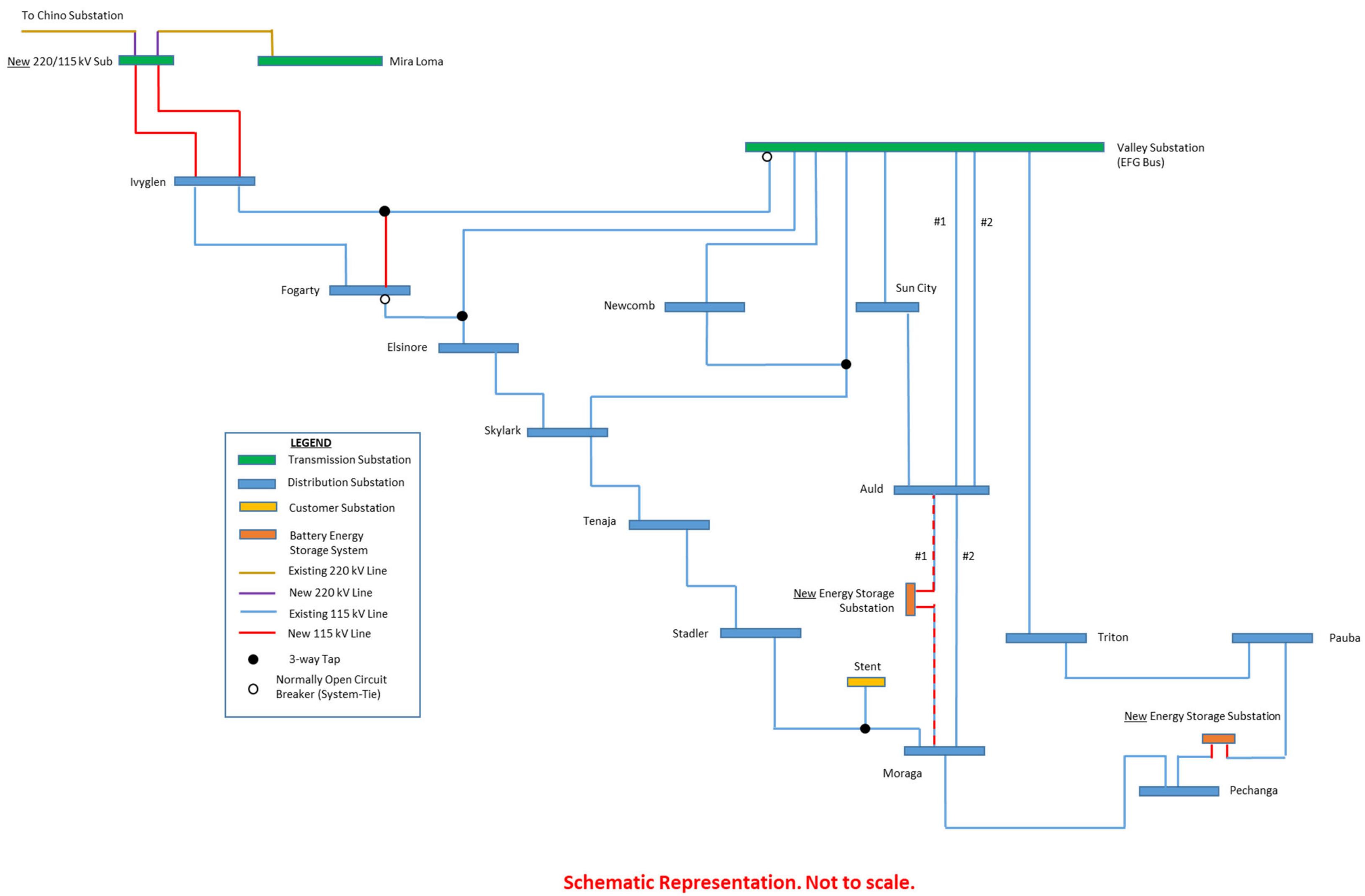


Figure C-22. System One-Line Schematic of the Mira Loma and Centralized BESS in Valley South Alternative

C.11.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 220/115 kV substation (approximately 15-acre footprint)
- Construct a new 220 kV double-circuit transmission line segment to loop SCE's existing Chino-Mira Loma 220 kV transmission line into SCE's new 220/115 kV substation (approximately 130 feet)
- Construct a new 115 kV double-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation (approximately 21.6 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to tap SCE's future Valley-Ivyglen 115 kV subtransmission line to SCE's existing 115 kV Fogarty Substation (approximately 0.6 mile)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Construct two new 115/12 kV substations with BESSs (each with an approximately 9-acre footprint)
- Construct two new 115 kV subtransmission segments to loop the new 115 kV BESS locations into SCE's existing 115 kV subtransmission system

In total, this system alternative would require the construction of approximately 29.4 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided in the subsections that follow.

New 220/115 kV Substation

The Mira Loma and Centralized BESS in Valley South system alternative would involve the construction of a new, approximately 15-acre, 220/115 kV substation on a privately owned, approximately 27-acre, vacant parcel. The parcel is located north of Ontario Ranch Road, east of Haven Avenue, and west of Hamner Avenue in the City of Ontario. The parcel is rectangular in shape and is bounded by vacant land to the north, SCE's existing 220 kV Mira Loma Substation and vacant land to the east, vacant land to the south, and vacant land and industrial uses to the west. The vacant parcel has a residential land use designation, and an existing SCE transmission corridor crosses the southeast portion of the site. Vehicular access would likely be established from Ontario Ranch Road.

New 220 kV Double-Circuit Transmission Line

A new 220 kV double-circuit transmission line segment would be constructed between the existing Chino-Mira Loma 220 kV transmission line and SCE's new 220/115 kV substation. This approximately 130-foot segment would begin within SCE's existing transmission corridor, approximately 2,000 feet east of Haven Avenue, and extend south until reaching SCE's new 220/115 kV substation site.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line would be constructed, connecting SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation. This line would exit the new 220/115 kV substation site from the southerly portion of the property and travel east in an underground configuration for approximately 0.2 miles along Ontario Ranch Road. The line would pass under SCE's existing transmission line corridor and then transition to an overhead configuration, continuing on new structures along Ontario Ranch Road for approximately 0.5 miles until intersecting Hamner Road. The line would then extend south along Hamner Road and parallel to SCE's existing Mira Loma-Corona 66 kV subtransmission line for approximately 6.8 miles. Within this approximately 6.8-miles portion of the route, the line would exit the City of Ontario and enter the City of Eastvale at the intersection with Bellegrave Avenue. Within the City of Eastvale, the line would continue along Hamner Avenue, cross the Santa Ana River, and enter the City of Norco. Within the City of Norco, the line would continue south along Hamner Avenue until intersecting 1st Street. At this point, the line would extend west along 1st Street for approximately 0.5 miles until West Parkridge Avenue. At this intersection, the line would enter the City of Corona and continue generally south along North Lincoln Avenue for approximately 3.2 miles, paralleling the Chase-Corona-Databank 66 kV subtransmission line between Railroad Street and West Ontario Avenue. At the intersection with West Ontario Avenue, the line would extend east and continue paralleling SCE's existing Chase-Corona-Databank 66 kV subtransmission line for approximately 1.4 miles until the intersection with Magnolia Avenue. The line would continue along West Ontario Avenue for approximately 0.2 mile, then it would parallel SCE's existing Chase-Jefferson 66 kV subtransmission line between Kellogg Avenue and I-15 for approximately 1.7 miles. The line would continue along East Ontario Avenue, pass under I-15, and exit the City of Corona after approximately 0.2 miles at the intersection of East Ontario Avenue and State Street. The line would extend southeast for approximately 1.8 miles along East Ontario Avenue within Riverside County until the intersection of Cajalco Road. At this intersection, the line would extend southeast along Temescal Canyon Road, crossing the City of Corona for approximately 1.2 miles between Cajalco Road and Dos Lagos Drive. The line would then continue within Riverside County along Temescal Canyon Road for approximately 3.9 miles before crossing under I-15 and terminating at SCE's existing 115 kV Ivyglen Substation. This segment of the system alternative would be approximately 21.6 miles in length.

New 115 kV Single-Circuit Subtransmission Line

A new 115 kV single-circuit subtransmission line segment would be constructed to tap SCE's future Valley-Ivyglen 115 kV subtransmission line into SCE's existing 115 kV Fogarty Substation. The new line segment would begin along the future Valley-Ivyglen 115 kV subtransmission line's alignment, approximately 680 feet southeast of the intersection of Pierce Street and Baker Street in the City of Lake Elsinore. The new line segment would extend generally southwest and parallel to SCE's existing Valley-Elsinore-Fogarty 115 kV subtransmission line until terminating at SCE's existing 115 kV Fogarty Substation. This segment of the system alternative would be approximately 0.6 miles in length.

Reconductor Existing 115 kV Subtransmission Lines

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

BESS and 115 kV Loop-Ins

Pechanga BESS and Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the City of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

Auld BESS and Loop-In

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 24.6-acre, privately owned parcel in the City of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld-Moraga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Auld BESS.

C.11.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-23 on the following page.

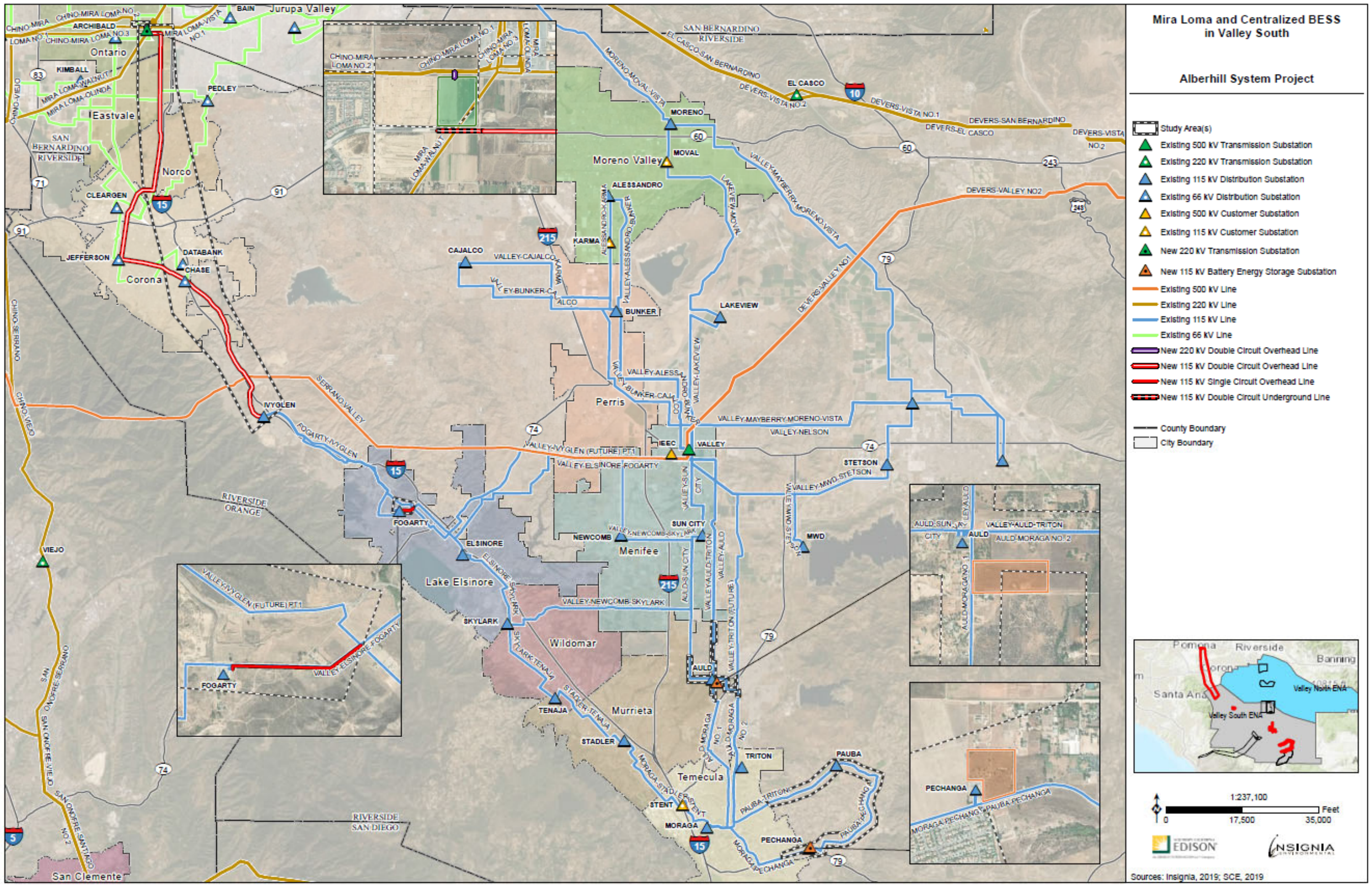


Figure C-23. Siting and Routing Map for the Mira Loma and Centralized BESS in Valley South Alternative[98]

[98] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.11.5 **Project Implementation Scope**

Table C-24 summarizes the scope for this alternative.

Table C-24. Mira Loma and Centralized BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 220/115 kV Substation	
Electrical	New (3) position, (4) element 220 kV breaker-and-a-half switchrack to accommodate (2) transformers & (2) lines
	(2) 280 MVA, 220/115 kV transformers
	New (4) position, (4) element 115 kV double-bus-double-breaker switchrack to accommodate (2) transformers & (2) lines
	220 and 115 kV line protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
New 115/12 kV Substation with BESS (adjacent to Auld Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV line protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 115/12 kV Substation with BESS (adjacent to Pechanga Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 220 kV Transmission Line	
Loop-in Chino-Mira Loma 220 kV Transmission Line to New 220/115 kV Substation	100 feet new overhead double-circuit

Scope	Detailed Scope Element
New 115 kV Subtransmission Lines	
Mira Loma-Ivyglen	21.6 miles (21.4 overhead double-circuit , 0.2 underground double-circuit)
Valley-Ivyglen to Fogarty	0.6 miles overhead single-circuit
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Mira Loma	(1) 220 kV line protection upgrade
Chino	(1) 220 kV line protection upgrade
Fogarty	Equip (1) 115 kV line position
Ivyglen	Remove No.3 capacitor from Position 1
	Equip (2) 115 kV line positions and (1) 115 kV line protection upgrade
Valley	(1) 115 kV line protection upgrade
Distribution	
Replace Existing Single-Circuit Overhead	Approximately 15,400 feet
Replace Existing Double-Circuit Overhead	Approximately 11,200 feet
Transmission Telecom	
Chino-Mira Loma 220 kV Line to New 220/115 Substation	100 feet overhead fiber optic cable
Mira Loma-Ivyglen	21.6 miles (21.4 overhead, 0.2 underground) fiber optic cable
Valley-Ivyglen to Fogarty	0.6 miles overhead fiber optic cable
Real Properties	
Mira Loma Substation D-C-02A	Fee Acquisition – (1) 26.78-Acre Parcel
Mira Loma-Ivyglen 115 kV Subtransmission Line	New Easement – (68) Parcels (10 miles, 30 ft. wide, 36.36 acres total)
Valley-Ivyglen to Fogarty 115 kV Subtransmission Line	New Easement – (10) Parcels (0.36 miles, 30 ft. wide, 1.31 acres total)
Pechanga BESS B-A-10	Fee Acquisition – (1) 16.9-Acre Parcel
Auld BESS A-C-04	Fee Acquisition – (1) 24.6-Acre Parcel
Mira Loma Laydown Yard	Lease – (1) 10-Acre Parcel for 92 months
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New 220/115 kV Substation and BESS Locations	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-25 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-25. Battery Installations

Year	PVWatts Forecast		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
2036	66	195	2031	83	247	2026	99	299
2041	34	194	2036	48	303	2031	52	373
2046	9	62	2041	43	296	2036	61	463
-	-	-	2046	12	106	2041	54	427
-	-	-	-	-	-	2046	18	157
Total	109	451	Total	186	952	Total	284	1719

C.11.6 **Cost Estimate Detail**

Table C-26 below summarizes the costs for this alternative under the three load forecast used in the cost benefit analysis.

Table C-26. Mira Loma and Centralized BESS in Valley South Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	118	140	157
Substation Estimate	105	126	142
Owners Agent (10% of construction)	13	14	15
Corporate Security	6	6	6
Bulk Transmission	3	3	3
Subtransmission	101	101	101
Transmission Telecom	3	3	3
Distribution	4	4	4
IT Telecom	4	4	4
RP	27	27	27
Environmental	26	26	26
Subtotal Direct Cost	**326**	**348**	**365**
Subtotal Battery Cost	**301**	**603**	**1,129**
Uncertainty	293	445	700
Total with Uncertainty	**920**	**1,396**	**2,194**
Total Capex	**920**	**1,396**	**2,194**
Battery Revenue	**14**	**40**	**89**
PVRR	**448**	**560**	**601**

C.12 Valley South to Valley North and Centralized BESS in Valley South and Valley North

C.12.1 **System Solution Overview**

The Valley South to Valley North alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to SCE's existing Valley North 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed.

To further reduce load in the Valley South System, a new 115/12 kV substation with BESS would be installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line and a second BESS will be installed at Alessandro Substation to offset a portion of the load that is transferred from the Valley South to Valley North System.

C.12.2 **System One-Line Schematic**

A System One-Line Schematic of this alternative is provided in Figure C-24 and Figure C-25 on the following pages (Valley North portion and Valley South portion, respectively).

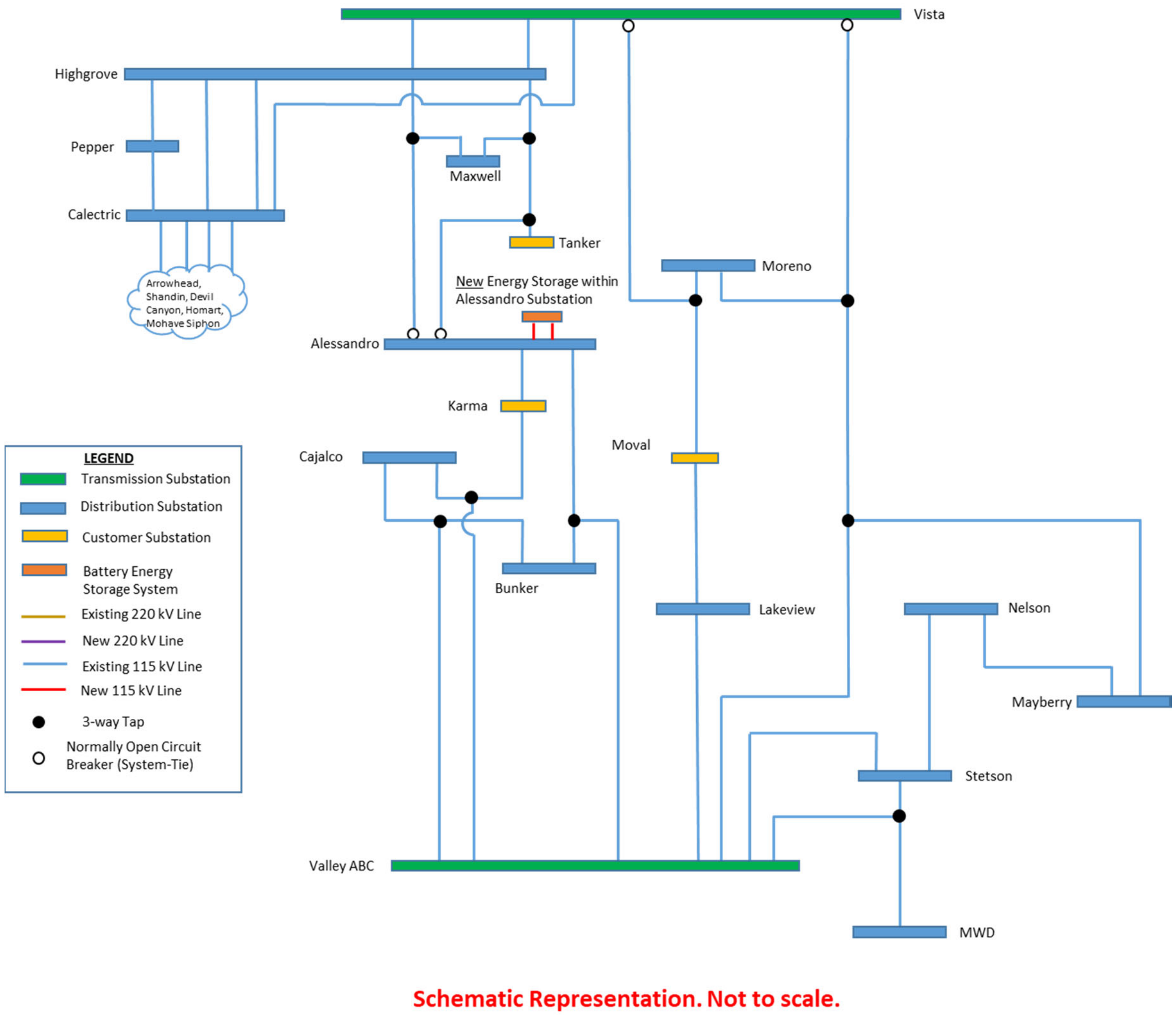
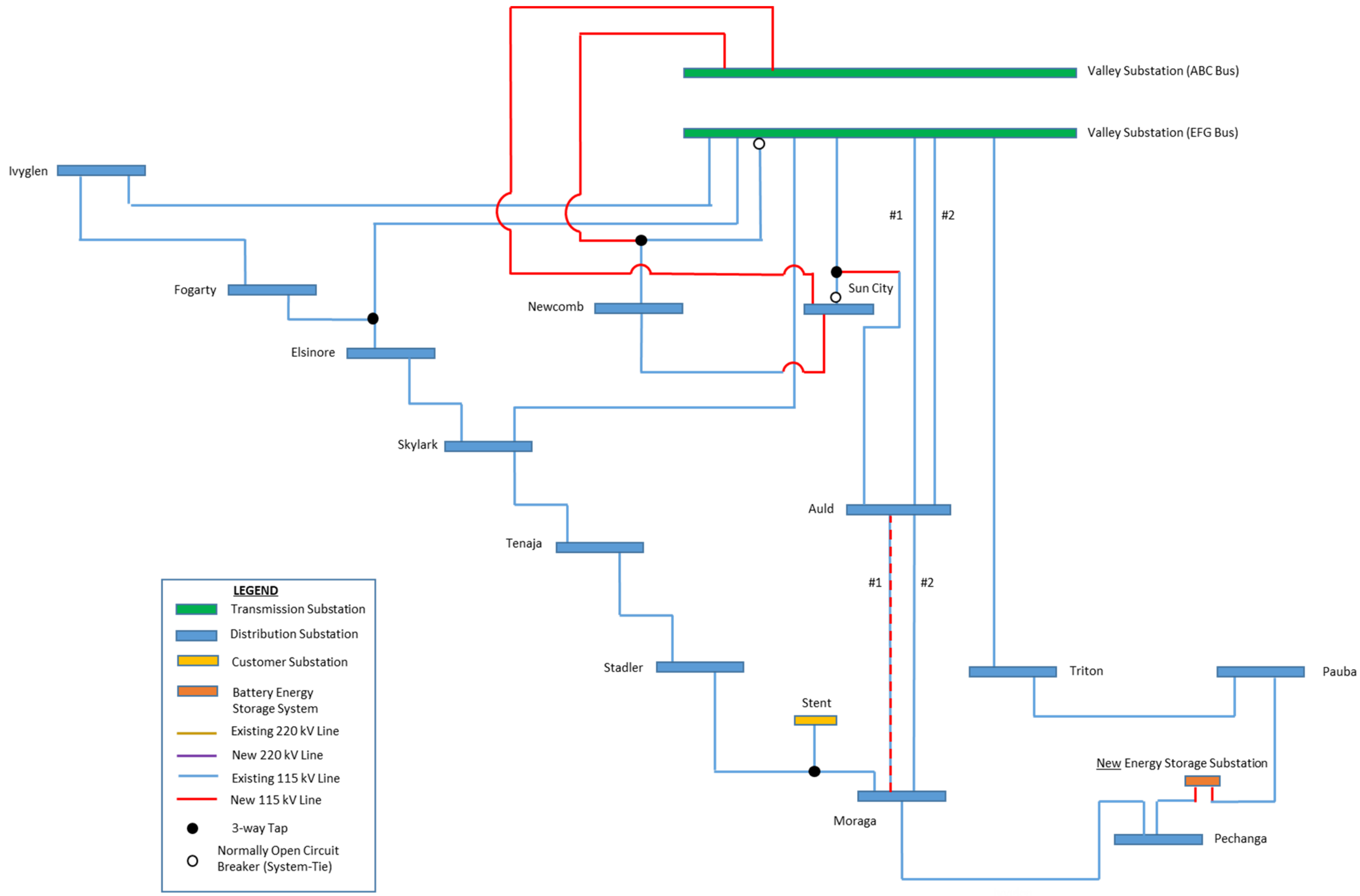


Figure C-24. System One-Line Schematic of the Valley South to Valley North and Centralized BESS in Valley South and Valley North Alternative (Valley North Portion)



Schematic Representation. Not to scale.

Figure C-25. System One-Line Schematic of the Valley South to Valley North and Centralized BESS in Valley South and Valley North Alternative (Valley South Portion)

C.12.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley and 115 kV Sun City Substations (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Construct one new 115/12 kV substation with BESS and add BESSs to an existing SCE substation
- Construct one new 115 kV subtransmission segment to loop the new BESS into SCE's existing subtransmission system

This system alternative would require the construction of approximately 13.1 miles of new 115 kV subtransmission line. A detailed description of each of these components is provided in the subsections that follow.

<u>New 115 kV Single-Circuit Subtransmission Lines</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld-Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Reconductor Existing 115 kV Subtransmission Lines

Auld-Moraga #1

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

BESS and 115 kV Loop-Ins

Pechanga BESS and Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the City of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga

115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

Alessandro BESS

The 115 kV Alessandro BESS would be constructed within SCE's existing 115 kV Alessandro Substation in the City of Moreno Valley. The existing substation is located on an approximately 24.2-acre parcel at the intersection of John F Kennedy Drive and Kitching Street. This site is bounded by residential development to the north, east, and south; and residential development and a school to the west.

C.12.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-26 on the following page.

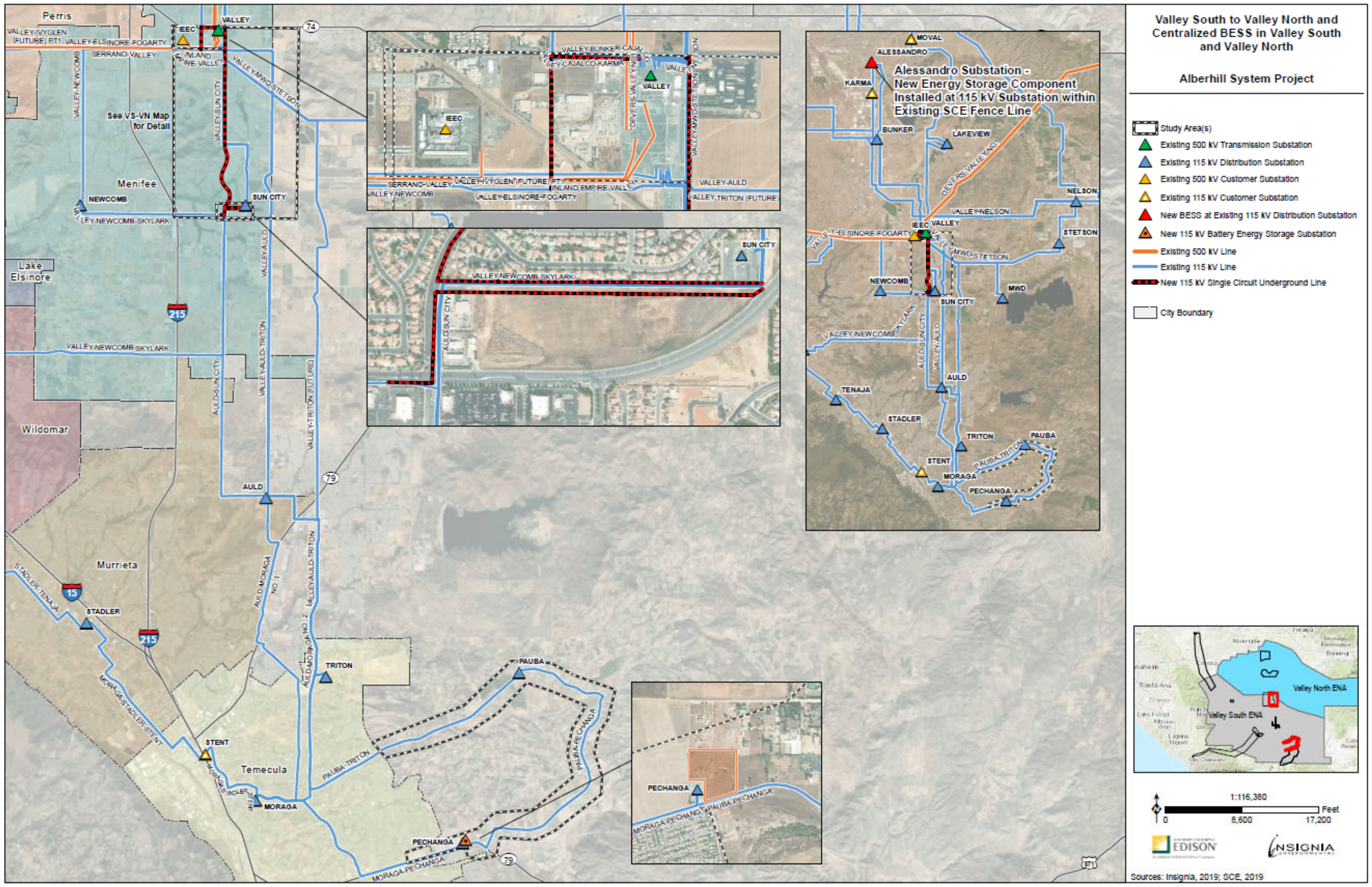


Figure C-26. Siting and Routing Map for the Valley South to Valley North and Centralized BESS in Valley South and Valley North Alternative[99]

[99] Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.12.5 **Project Implementation Scope**

Table C-26 summarizes the scope for this alternative.

Table C-26. Valley South to Valley North and Centralized BESS in Valley South and Valley North Scope Table

Scope	Detailed Scope Element
System Scope Elements	
BESS in Alessandro Substation**	
Electrical	Equip (3) 115 kV positions on the existing switchrack to accommodate (3) transformers
	(6) 28 MVA, 115/33kV transformers
	(3) new, (12) position 33 kV operating/transfer switchracks
	115 and 33 kV Line Protection
Civil	Foundations for all substation equipment
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	300 MW/ 1500 MWh
New 115/12 kV Substation with BESS (adjacent to Pechanga Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position, repurpose Position No. 2 for 115 kV Line with (1) line protection upgrade, and (1) line protection upgrade
Valley	Equip 115 kV Position 7 with (2) new 115 kV Lines, and (2) line protection upgrades on EFG Bus.
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 18,900 feet

Scope	Detailed Scope Element
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Real Properties	
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Pechanga BESS Location B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New BESS Locations	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-27 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-27. Battery Installations

Year	PVWatts Forecast		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
2040 (VS)	67	204	2037 (VN)	83	290	2030 (VN)	97	375
2045 (VS)	27	165	2042 (VN)	46	335	2035 (VN)	77	635
-	-	-	2043 (VS)	39	108	2036 (VS)	81	242
-	-	-	2046 (VS)	10	42	2040 (VN)	72	704
-	-	-	2046 (VN)	18	165	2041 (VS)	49	291
-	-	-	-	-	-	2045 (VN)	39	418
-	-	-	-	-	-	2046 (VS)	18	114
Total (VS)	94	369	Total (VN)	147	790	Total (VN)	285	2132
			Total (VS)	49	150	Total (VS)	148	647

C.12.6 **Cost Estimate Detail**

Table C-28 summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-28. Valley South to Valley North and Centralized BESS in Valley South and Valley North Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	40	89	116
Substation Estimate	34	80	106
Owners Agent (10% of construction)	6	9	10
Corporate Security	3	3	3
Bulk Transmission	n/a	n/a	n/a
Subtransmission	78	78	78
Transmission Telecom	2	2	2
Distribution	n/a	n/a	n/a
IT Telecom	2	2	2
RP	5	5	5
Environmental	18	18	18
Subtotal Direct Cost	**213**	**230**	**258**
Subtotal Battery Cost	**226**	**606**	**1,598**
Uncertainty	164	336	760
Total with Uncertainty	**572**	**1,172**	**2,616**
Total Capex	**572**	**1,172**	**2,616**
Battery Revenue	**7**	**20**	**88**
PVRR	**255**	**367**	**700**

C.13 Valley South to Valley North to Vista and Centralized BESS in Valley South

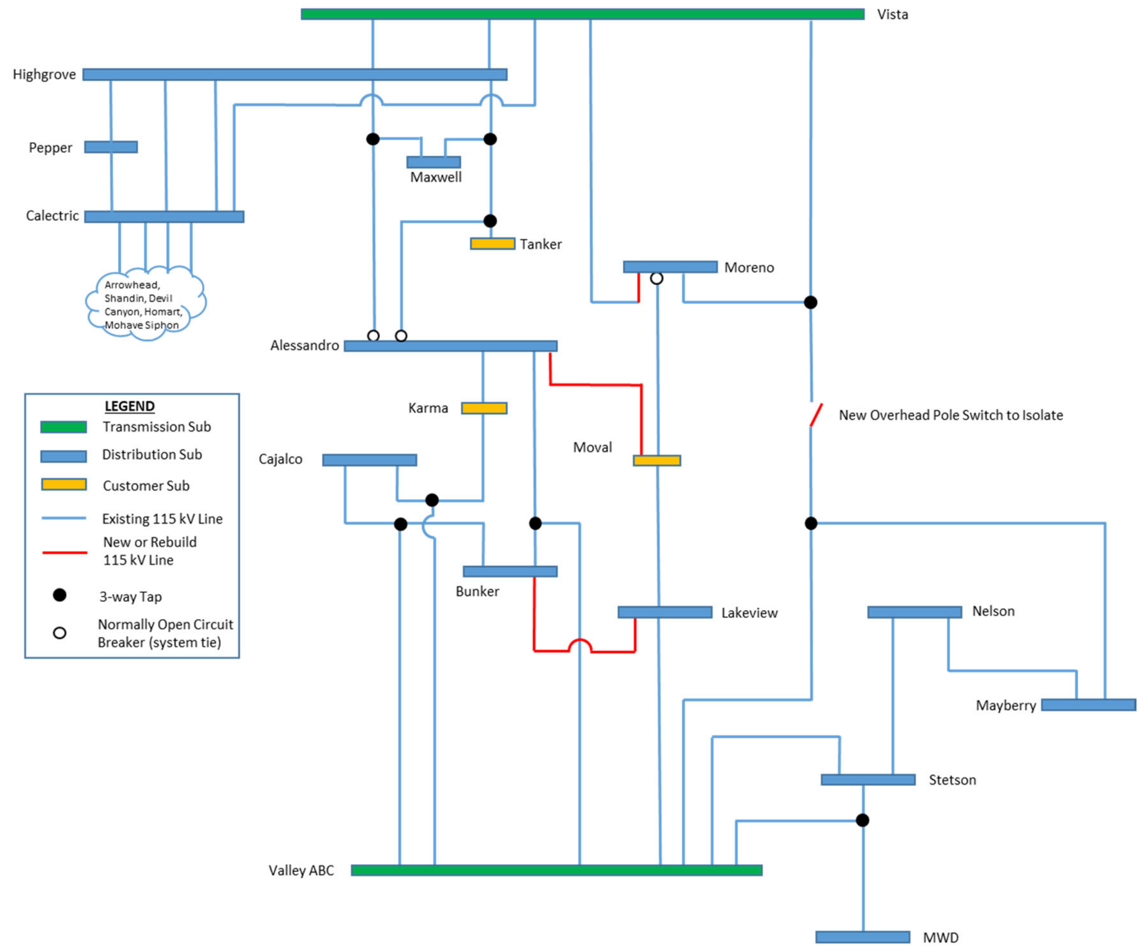
C.13.1 System Solution Overview

The Valley South to Valley North to Vista alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to the Valley North 500/115 kV System, and away from the Valley North 500/115 kV System to the Vista 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations from the Valley South to the Valley North System, and the Moreno 115/12 kV distribution substation to the Vista System. Subtransmission line construction and modifications in Valley South create two system-ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North system back to the Valley South System (one or both Sun City and Newcomb Substations) as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed. Subtransmission line construction and modifications in Valley North create two system-ties between the Valley North and Vista Systems. These system-tie lines would allow for the transfer of load from the Vista system back to the Valley North System (Moreno Substation) as well as additional load transfer from the Valley North System to the Vista System (Mayberry Substation) as needed.

To further reduce load in the Valley South System, a new 115/12 kV substation with BESS would be installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line.

C.13.2 System One-Line Schematic

A System One-Line Schematic of this alternative is provided in Figure C-27 and Figure C-28 on the following pages (Valley North and Valley South portions, respectively).



Schematic Representation. Not to scale.

Figure C-27. System One-Line Schematic of the Valley South to Valley North to Vista and Centralized BESS in Valley South (Valley North Portion)

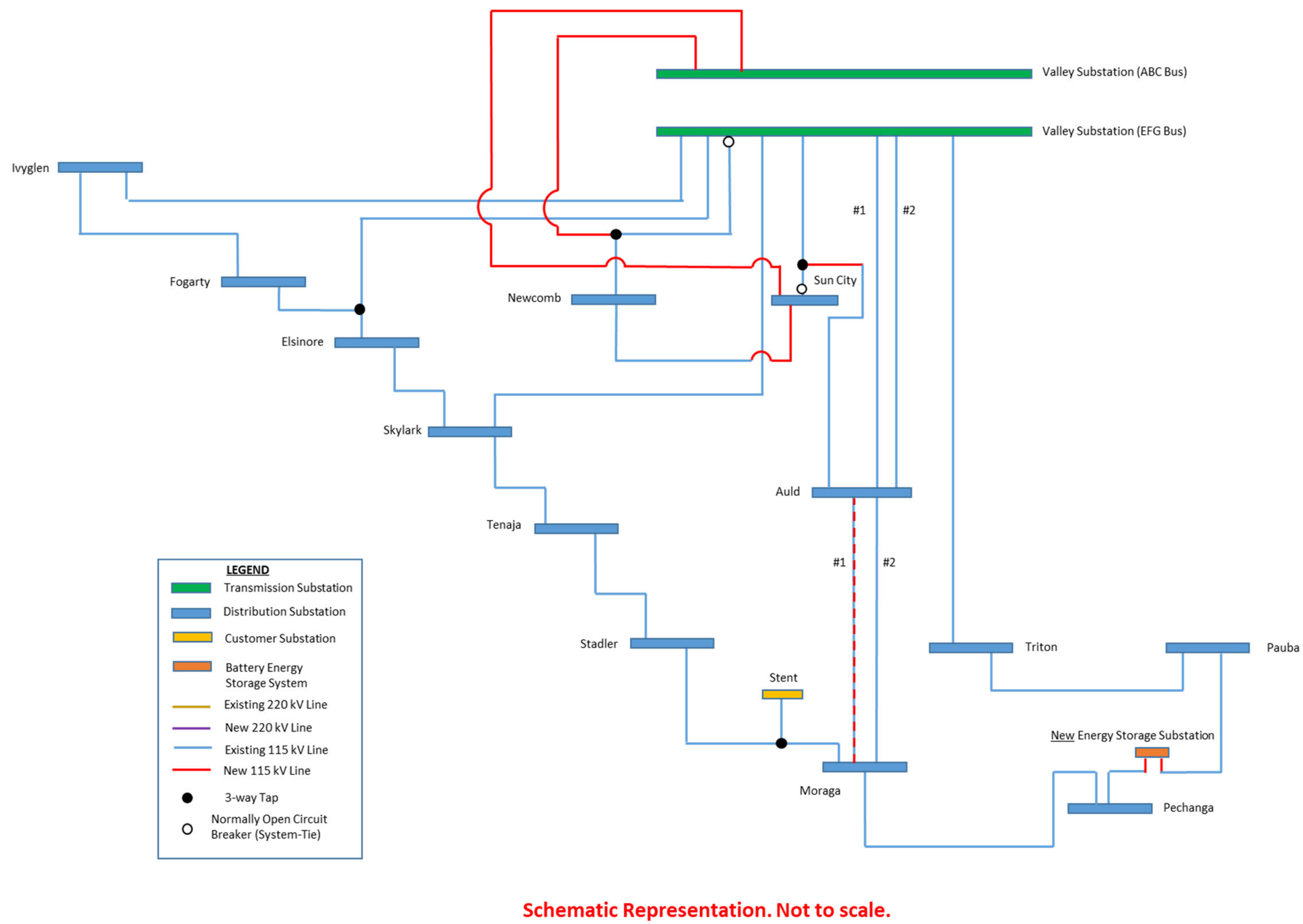


Figure C-28. System One-Line Schematic of the Valley South to Valley North to Vista and Centralized BESS in Valley South (Valley South Portion)

C.13.3 **Siting and Routing Description**

This system alternative would include the following components:

- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley and 115 kV Sun City Substations (approximately 4.4 miles)
- Construct a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construct a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductor SCE's existing, single-circuit Auld-Moraga #1 115 kV subtransmission line (approximately 7.2 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 115 kV Bunker and Lakeview Substations (approximately 6 miles)
- Construct a new 115 kV single-circuit subtransmission line between SCE's existing 115 kV Alessandro and Moval Substations (approximately 4 miles)
- Double-circuit a segment of SCE's existing 115 kV Moreno-Moval-Vista subtransmission line (approximately 0.1 mile)
- Construct one new 115/12 kV substation with BESS (approximately 9-acre footprint)
- Construct one new 115 kV subtransmission segment to loop the new 115 kV BESS into SCE's existing 115 kV subtransmission system

This system alternative would require the construction of approximately 15.9 miles of new 115 kV subtransmission line and the modification of approximately 7.3 miles of existing 115 kV subtransmission line. This system alternative totals approximately 23.2 miles. A detailed description of each of these components is provided in the subsections that follow.

<u>New 115 kV Single-Circuit Subtransmission Lines</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the City of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend approximately 3.9 miles south along Menifee Road until reaching SCE's existing Auld-Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east and parallel to the Auld-Sun City 115 kV subtransmission line for approximately 0.5 until reaching SCE's existing 115 kV Sun City Substation. This segment of the system alternative would be approximately 4.4 miles in length.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and 500 kV Valley Substation in the City of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the system alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west and parallel to SCE's existing Auld-Sun City 115 kV subtransmission line until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west for approximately 350 feet along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line until terminating at an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the system alternative would be approximately 0.7 miles in length.

Bunker Substation to Lakeview Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Bunker Substation in the City of Perris and 115 kV Lakeview Substation in Riverside County. From SCE's existing 115 kV Bunker Substation, the line would extend south on Wilson Avenue on new structures for approximately 0.4 miles until the intersection with Placentia Avenue. At this intersection, the line would extend east on Placentia Avenue for approximately 0.4 mile, then turn south for approximately 0.3 miles and travel parallel to a dry creek bed until the intersection with Water Avenue. At the intersection with Water Avenue, the line would leave the City of Perris and extend east for approximately 0.8 miles until the intersection with Bradley Road. The line would then continue east across vacant and agricultural lands for approximately 2.1 miles until intersecting SCE's existing Valley-Lakeview 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Valley-Lakeview 115 kV subtransmission line for approximately 2 miles, then extend north until terminating at SCE's existing 115 kV Lakeview Substation. The current route extends north, southeast along 11th Street, and northeast along an unpaved access road before arriving at SCE's existing 115 kV Lakeview Substation. This segment of the system alternative would be approximately 6 miles in length.

Alessandro Substation to Moval Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Alessandro and Moval Substations in the City of Moreno Valley. The new line would exit SCE's existing 115 kV Alessandro Substation in an underground configuration and extend north for approximately 350 feet along Kitching Street until intersecting John F Kennedy Drive. At this intersection, the line would transition to an overhead configuration on new structures and extend east along John F Kennedy Drive for approximately 0.5 miles until the intersection with Lasselle Street. The line would then extend north on Lasselle Street for approximately 1 miles until the intersection with Alessandro Boulevard, where the line would extend east for approximately 2 miles until intersecting Moreno Beach Drive and SCE's existing Lakeview-Moval 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Lakeview-Moval 115 kV subtransmission line for approximately 0.5 miles until terminating at SCE's existing 115 kV Moval Substation. The current route extends north along Moreno Beach Drive until reaching SCE's existing 115 kV Moval Substation, approximately 0.1 miles south of the intersection of Moreno Beach Drive and Cottonwood Avenue. This segment of the system alternative would be approximately 4 miles in length.

Double-Circuit Existing 115 kV Subtransmission Line

SCE currently operates an existing, single-circuit Moreno-Moval-Vista 115 kV subtransmission line between SCE's existing 115 kV Moreno, Moval, and Vista Substations. An approximately 0.1-miles segment of this line within the City of Moreno Valley would be converted from a single-circuit to double-circuit configuration. This segment would begin at the intersection of Ironwood Avenue and Pettit Street and extend east before turning north and entering SCE's existing 115 kV Moreno Substation.

Reconductor Existing 115 kV Subtransmission Lines

SCE's existing Auld-Moraga #1 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Moraga Substations. This component would begin at SCE's existing 115 kV Auld Substation in the City of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the east and continues south along Liberty Lane and Crosspatch Road. The line continues south along unpaved roads for approximately 0.5 miles until turning southeast for approximately 0.25 miles to Highway 79. The line follows Highway 79 approximately 2 miles until reaching Murrieta Hot Springs Road. The line then turns south onto Sky Canyon Drive and then immediately southeast on an unpaved access road and continues to traverse through a residential neighborhood for approximately 1 mile. The line then turns south and traverses through residential neighborhoods for approximately 2.5 miles before turning west near the corner of Southern Cross Road and Agena Street. The line then continues west for approximately 1 mile while traversing through residential neighborhood until reaching SCE's existing 115 kV Moraga Substation. This segment of the system alternative would be approximately 7.2 miles in length.

BESS and 115 kV Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the City of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

C.13.4 Siting and Routing Map

A siting and routing map of this alternative is provided in Figure C-29 on the following page.

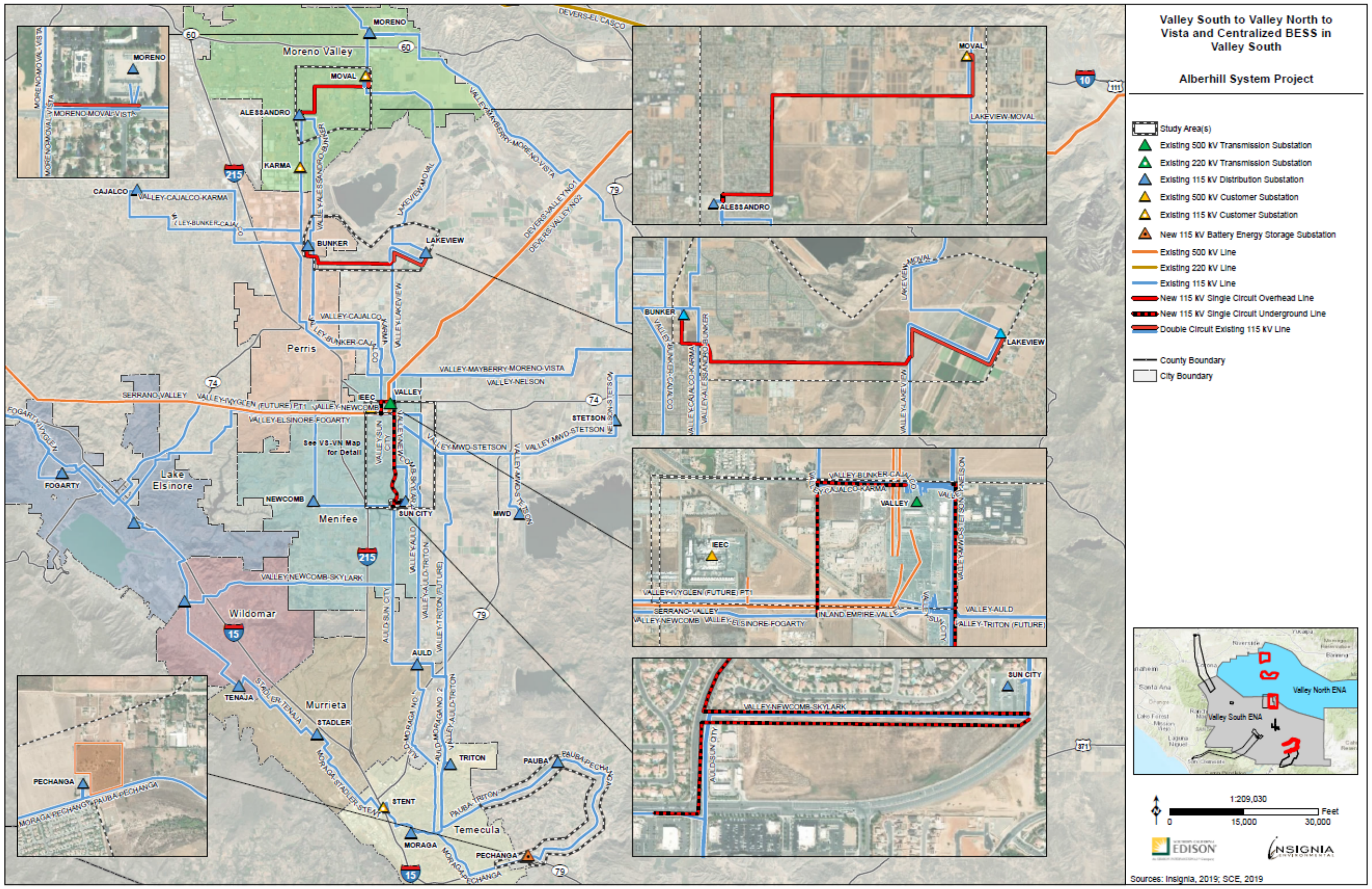


Figure C-29. Siting and Routing Map for the Valley South to Valley North to Vista and Centralized BESS in Valley South Alternative[100]

100 Note that the Auld-Moraga #1 reconductor scope is not shown on this siting and routing map.

C.13.5 **Project Implementation Scope**

Table C-28 summarizes the scope for this alternative.

Table C-28. Valley South to Valley North to Vista and Centralized BESS in Valley South Scope Table

Scope	Detailed Scope Element
System Scope Elements	
New 115/12 kV Substation with BESS (adjacent to Pechanga Substation)**	
Electrical	New (3) position, (6) element 115 kV breaker-and-a-half switchrack to accommodate (4) transformers & (2) lines
	(8) 28 MVA, 115/12 kV transformers
	(2) new (14) position, 12 kV operating/transfer switchracks
	115 and 12 kV Line Protection
Civil	Foundations for all substation equipment, grading, cut/fill, site prep, etc.
Telecom IT	(1) Mechanical Electrical Equipment Room (MEER)
Batteries	200 MW/1000 MWh
New 115 kV Subtransmission Lines	
Valley North-Sun City	4.4 miles underground single-circuit
Newcomb-Valley North	0.8 miles underground single-circuit
Sun City-Newcomb	0.7 miles underground single-circuit
Auld-Sun City	7.7 miles overhead reconductor existing
Alessandro-Moval	4 miles (3.5 overhead single-circuit , 0.1 underground single-circuit , and 0.4 overhead double-circuit existing)
Bunker-Lakeview	6 miles (3.9 overhead single-circuit , 2.1 overhead double-circuit existing)
Moreno-Moval	0.1 miles overhead double-circuit existing
Auld-Moraga #1	7.2 miles overhead reconductor existing
Support Scope Elements	
Substation Upgrades	
Auld	(1) 115 kV line protection upgrade
Newcomb	(2) 115 kV line protection upgrades
Sun City	Equip (1) 115 kV line position , repurpose Position No. 2 for 115 kV Line with (1) line protection upgrade, and (1) line protection upgrade
Valley ABC	Equip 115 kV Position 7 with (2) new 115 kV Lines, and (2) line protection upgrades on Valley South Switchrack.
Moreno	(1) 115 kV line position
Moval	(2) 115 kV line position & (1) line protection upgrade
Bunker	Equip (1) 115 kV line position
Lakeview	Equip (1) 115 kV line position

Scope	Detailed Scope Element
Alessandro	Build and equip (1) 115 kV line position
Distribution	
Replace Existing Single-Circuit Underbuild	Approximately 19,200 feet
Replace Existing Single-Circuit Overhead	Approximately 12,800 feet
Transmission Telecom	
Valley North-Sun City	4.4 miles underground fiber optic cable
Newcomb-Valley North	0.8 miles underground fiber optic cable
Sun City-Newcomb	0.7 miles underground fiber optic cable
Auld-Sun City	7.7 miles overhead fiber optic cable
Alessandro-Moval	4 miles (3.9 overhead, 0.1 underground) fiber optic cable
Bunker-Lakeview	6. miles overhead fiber optic cable
Real Properties	
Alessandro-Moval	New Easement – (20) Parcels (1 mile, 30 ft. wide, 9.09 acres total)
Bunker-Lakeview	New Easement – (45) Parcels (5 miles, 30 ft. wide, 18.18 acres total)
Newcomb-Valley North	New Easement – (4) Parcels (0.25 miles, 30 ft. wide, 0.91 acres total)
Sun City-Newcomb	New Easement – (6) Parcels (0.68 miles, 30 ft. wide, 2.5 acres total)
Valley North-Sun City	New Easement – (7) Parcels (0.5 miles, 30 ft. wide, 1.8 acres total)
Pechanga BESS Location B-A-10	Fee Acquisition – (1) 16.93-Acre Parcel
Environmental	
All New Construction	Environmental Licensing, Permit Acquisition, Documentation Preparation and Review, Surveys, Monitoring, Site Restoration, etc.
Corporate Security	
New BESS Locations	Access Control System, Video Surveillance, Intercom System, Gating, etc.

**Scope for BESS sites in this table are based on the Effective PV load forecast.

Table C-29 summarizes the incremental battery installations for this alternative. Three different load forecasts were used in the cost benefit analysis. The sizing and installation timing of the BESS sites and batteries differs depending on the load forecast. See Section 5 for additional information.

Table C-29. Battery Installations

Year	PVWatts Forecast[1]		Year	Effective PV Forecast		Year	Spatial Base Forecast	
	MW	MWh		MW	MWh		MW	MWh
-	-	-	2043	39	108	2036	81	242
-	-	-	2046	10	42	2041	49	291
-	-	-	-	-	-	2046	18	114
-	-	-	Total	49	150	Total	148	647

Note:

1. The PVWatts forecast does not necessitate a need for batteries to meet N-0 capacity requirements, i.e., the conventional scope of this alternative alone mitigates all N-0 transformer capacity overloads through the 30 -year horizon of the cost benefit analysis.

C.13.6 **Cost Estimate Detail**

Table C-30 below summarizes the costs for this alternative under the three load forecasts used in the cost benefit analysis.

Table C-30. Valley South to Valley North to Vista and Centralized BESS in Valley South Cost Table

Project Element	Cost ($M)		
	PVWatts Forecast[1]	Effective PV Forecast	Spatial Base Forecast
Licensing	31	31	31
Substation	17	53	68
Substation Estimate	8	44	58
Owners Agent (10% of construction)	8	9	10
Corporate Security	n/a	2	2
Bulk Transmission	n/a	n/a	n/a
Subtransmission	109	109	109
Transmission Telecom	3	3	3
Distribution	3	1	1
IT Telecom	2	2	2
RP	18	18	18
Environmental	29	29	29
Subtotal Direct Cost	**213**	**250**	**265**
Subtotal Battery Cost	**n/a**	**101**	**422**
Uncertainty	95	153	298
Total with Uncertainty	**307**	**505**	**986**
Total Capex	**307**	**505**	**986**
Battery Revenue	**n/a**	**2**	**18**
PVRR	**269**	**289**	**404**

Note:

1. The PVWatts forecast does not necessitate a need for batteries. The scope for this alternative under the PVWatts forecast is identical to the VS-VN-Vista alternative.

D Appendix – Uncertainty Scoring

The uncertainty scoring details for the Alberhill System Project and all project alternatives is provided in Table D-1. The impact of each uncertainty category on project schedule and budget was scored using a low, medium and high scale (low being a 1, medium being a 3, and high being a 5). Each uncertainty category was characterized as having a low, medium, or high (1, 3, or 5, respectively) impact on project schedule and budget. For each alternative, the likelihood that a specific uncertainty category would apply to that alternative was also scored on a not applicable, low, medium, or high basis (0, 1, 3, or 5, respectively). The uncertainty impact score was multiplied by each alternative's uncertainty likelihood score. This result for each uncertainty category was summed together for all alternatives to establish the final uncertainty score of the alternative.

Table D-1 – Uncertainty Scoring

Uncertainty Categories	Impact	Alberhill	SDG&E	SCE Orange County	Menifee	Mira Loma	Valley South to Valley North	Valley South to Valley North to Vista	Centralized BESS in Valley South	Valley North to Valley South and Distributed BESS in Valley South	SDGE and Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South
General Project														
Site and Route Local Public Opposition (Delay)	5	1	5	3	5	5	5	5	1	1	5	5	5	5
Other Local Development Activities Impact Site or Route (Delay)	3	3	5	3	3	5	3	3	1	3	5	5	3	3
Material Delays	1	1	3	3	5	3	3	3	5	5	5	5	5	5
Nesting Birds	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Agency Permitting Delays	5	3	5	5	3	3	3	3	3	3	5	3	3	3
Labor Market Conditions	3	3	5	5	3	5	3	3	1	3	5	5	3	3
Subtotal		48	92	76	72	82	70	70	40	52	94	84	72	72
Transmission/Subtransmission														
Property Acquisition	5	1	1	5	3	5	3	5	1	1	1	5	3	5
Cultural Resources	3	1	5	5	3	3	3	3	3	3	5	3	3	3
Biological Resources	3	1	5	5	3	3	3	3	3	3	5	3	3	3
Unknown Underground Conditions	3	1	3	3	5	5	5	5	3	5	3	5	5	5
Lack of Geotechnical Data/Design	3	3	3	5	3	3	3	3	3	3	3	3	3	3
Required Undergrounding	5	1	5	3	5	5	5	5	1	5	5	5	5	5
Outage Constraints Due to Existing Facilities	3	5	5	5	5	5	3	3	1	1	5	5	3	3
High Fire Areas (Stop Work)	3	3	5	1	3	1	3	3	5	3	5	1	3	3
Future Requirement for Subtransmission Covered Conductor	3	3	1	1	1	1	1	1	1	1	1	1	1	1
Uncertainty in Distribution Scope Due to Lack of Design	3	1	3	3	3	3	3	3	1	1	3	3	1	3
Change in Standards	1	3	3	3	3	3	3	3	3	3	3	3	3	3
Tariff/Commodity Material Cost Changes	3	1	1	1	1	1	1	1	1	1	1	1	1	1
Transmission Access Roads	5	1	3	3	0	0	0	0	0	0	3	0	0	0
Subtotal		75	141	145	124	128	118	128	76	96	141	128	112	128
Substation														
Cultural Resources	3	1	5	5	3	3	0	0	5	1	5	3	5	5
Biological Resources	3	1	5	5	3	3	0	0	5	1	5	3	5	5
Unknown Underground Conditions	3	1	1	1	3	5	0	0	1	1	1	5	1	1
Lack of Geotechnical Data/Design	3	3	3	3	3	3	0	0	3	1	3	3	3	3
Change in Standards	1	3	3	3	3	3	0	0	3	3	3	3	3	3
Equipment Tariffs (Substation)	3	1	1	1	1	1	0	0	1	1	1	1	1	1
Ground Grid	1	3	3	3	3	3	0	0	3	0	3	3	3	3

Table D-1 – Uncertainty Scoring

Uncertainty Categories	Impact	Alberhill	SDG&E	SCE Orange County	Menifee	Mira Loma	Valley South to Valley North	Valley South to Valley North to Vista	Centralized BESS in Valley South	Valley North to Valley South and Distributed BESS in Valley South	SDGE and Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South
Change in Corporate Security Scope	1	3	3	3	3	3	0	0	3	0	3	3	3	3
Subtotal		30	54	54	48	54	0	0	54	18	54	54	54	54
Battery (Specific)														
Hazardous Material disposal	1	0	0	0	0	0	0	0	3	3	3	3	3	3
Additional Fire Risk Modification Costs	1	0	0	0	0	0	0	0	5	5	5	5	5	5
Assumed Price Decline Not Realized	3	0	0	0	0	0	0	0	1	1	1	1	1	1
Subtotal		0	0	0	0	0	0	0	11	11	11	11	11	11
Total Uncertainty Score		**153**	**287**	**275**	**244**	**264**	**188**	**198**	**181**	**177**	**300**	**277**	**249**	**265**
Total Uncertainty Costs		**26%**	**48%**	**46%**	**41%**	**44%**	**32%**	**33%**	**31%**	**30%**	**50%**	**46%**	**42%**	**44%**

EXHIBIT F-1 (SECOND AMENDED)

Item F:

The forecasted impact of the proposed project on **service reliability performance**, using electric service reliability metrics where applicable.

Response to Item F:

Revision 1.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This Second Amended Motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 1

Revision Date: February 2, 2021

Summary of Revisions:

- Modifies the terminology for the primary metric (previously Expected Energy Not Served (EENS) and now Load at Risk (LAR)) to clarify that the metrics are cumulative values of the potential amount of unserved load and are not probability weighted to associate the frequency and timing of events that would prompt loss of service to customers.
- Deletes the SAIFI, SAIDI and CAIFI metrics to avoid confusion with similar data reported in Supplemental Data Response Items B and C[1] which are calculated on the basis of a different customer base and thus cannot be compared directly. Because these SAIFI, SAIDI and CAIDI values previously provided here were derived from the LAR values they did not provide any additional insight on the effectiveness of the Alberhill System Project in meeting system reliability/resiliency needs.
- Modifies the description of the Flex-1 and Flex-2 metrics to reflect more realistic operation scenarios.

[1] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item C and DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item D.

1.0 Executive Summary

SCE interprets this data request as inquiring about the service reliability performance of the proposed Alberhill System Project (ASP)[2].

The proposed ASP was designed to mitigate the transformer capacity shortfall currently anticipated to occur in the Valley South System as early as 2022, while also addressing the long-standing need for system tie-lines to improve reliability and resiliency by providing the ability to transfer load to adjacent systems for maintenance and other activities (planned outages), and under abnormal system operating conditions (unplanned outages). To evaluate the impact of the proposed project on service reliability performance, the response to this data request uses forward-looking service reliability performance metrics, related to customers and energy at risk due to service interruption, to demonstrate that the ASP meets the identified project needs for capacity, reliability, and resiliency over both short-term (10 year) and long-term (30 year) horizons. These metrics demonstrate that the ASP reduces the customer risk of loss of service due to outages related to capacity, reliability, and resiliency issues by 99% through 2028, and by 97% through 2048[3]. These reductions sufficiently improve system performance to comply with SCE's planning standards[4] through 2038, with only one line reconductoring project needed to satisfy these criteria through 2048.

2.0 Introduction

As discussed throughout the ASP Certificate of Convenience and Necessity (CPCN) proceeding (A.09-09-022) and specifically highlighted in an earlier supplemental data request response[5], the reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity[6] margin, configuration, and size that make the Valley South subtransmission system[7] much more vulnerable to future reliability[8] problems than any other Southern California Edison (SCE) subtransmission system. Specifically, in its current status, the Valley South System operates at or very close to its maximum operating limits, has no connections

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[2] Service reliability results for alternatives to the Alberhill System Project, which were studied in the cost benefit analysis described in DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C, can be found in Quanta Technology Report, *Benefit Cost Analysis of Alternatives.*

[3] These percentages capture the projected cumulative percent reduction in unserved customer energy needs for various line and transformer outage contingency conditions (through 2028 and 2048 respectively) that are achieved as a result of ASP being in service.

[4] See Southern California Edison Subtransmission Planning Criteria and Guidelines, September 24, 2015.

[5] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B.

[6] *"Capacity"* is defined as the availability of electric power to serve load and is primarily comprised of two elements in a *radial transmission system*; a lack of capacity of either type will lead to reliability challenges in a radial subtransmission system: (1) "*transformation capacity"* – the ability to deliver power from the transmission system (through substation transformers); and (2) "*subtransmission system line capacity"* – the ability to deliver power to substations which directly serve the customer load in an area. Subtransmission system line capacity also includes "*system tie-line capacity*," which is the ability to transfer load to an adjacent subtransmission system to avoid, and reduce the number of customer's affected by, planned and unplanned outages in the system. Note, a *radial subtransmission system* is one that is provided power from a single source on the transmission system. This is in contrast to a networked system which has multiple transmission and subtransmission source connections. Almost all of SCE's subtransmission systems are of a radial design.

[7] While Southern California Edison typically considers a planning area to be at the substation level, for the purpose of this data request, the discussion herein focuses on the Valley South System, as it is most relevant to the Alberhill System Project proceedings. Certain characteristics discussed here may have broader impacts (on the Valley North System specifically, given the split nature of these systems), but the focus of this response remains on the Valley South System.

[8] *"Reliability*" is defined as a utility's ability to meet service requirements under normal and N-1 contingency conditions, both on a short-term and long-term basis. The ability to meet long-term capacity needs of a given system is an important aspect of reliability. This definition is consistent with IEEE 1366*, "IEEE Guide for Electric Power Distribution Reliability Indices"* which excludes extraordinary events from reliability data reporting.

(system tie-lines) to other systems, and represents the largest concentration of customers on a single substation in SCE's entire system. These characteristics threaten the future ability of the Valley South System to serve load under normal and abnormal conditions.

Also discussed in this proceeding, in the case of a catastrophic event (such as a major fire, earthquake, or incident at Valley Substation), SCE's ability to maintain service or to restore power in the event of an outage is significantly limited by the concentration of source power in a single location at Valley Substation[9]. This characteristic, in combination with others described in this submittal, results in specific concerns for the Valley South System from a resiliency[10] perspective.

In an earlier supplemental data request response[11], SCE provided an analysis of several years of electric reliability performance for the Valley Systems to demonstrate existing customer service metrics. SCE provided data for Valley South (and Valley North) historical reliability metrics (SAIDI and SAIFI) compared to other SCE subtransmission systems. These data show that, to date, the capacity of the Valley South System has been sufficient to serve all system customers under commonly planned for normal and extreme weather conditions. SCE noted that while SAIDI and SAIFI data are the principal metrics used to report on historical system reliability, they are primarily influenced by events at the distribution system level and thus are less informative for planning at the subtransmission system level. This is because when an electric power system has sufficient substation transformer capacity and/or sufficient system tie-line capacity, and is properly maintained and operated, reliability performance is driven largely by random, distribution-level events. Importantly, as SCE stated, the past reliability performance of the Valley Systems is not a driver for the proposed ASP project. Given the limited remaining transformer capacity serving the Valley South System and its lack of system tie-lines, the future reliability performance of the Valley South System will be driven less by random, distribution level events, and more by subtransmission level events that cannot be mitigated due to the lack of capacity margin and/or system tie-lines. These events would otherwise be mitigated by operational flexibility enabled by available transformer and system tie-line capacity to allow for short-term line and transformer overloads (per standards) to be addressed through the transfer of distribution substations to an adjacent system.

This data request response evaluates the Valley South System with and without the ASP and compares the reliability performance of the two system configurations using a set of *forward-looking* reliability and resiliency metrics related directly to SCE's ability to serve customer load throughout this specific electrical needs area. The analysis presented herein was developed and implemented collaboratively between SCE and a contractor, Quanta Technology[12], and documented in the attached report by Quanta Technology (see Appendix A).

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[9] The source of power to the Valley South System passes through a single point of delivery at Valley Substation, which is connected to the CAISO-controlled Bulk Electric System at the 500 kV voltage level.

[10] *"Resiliency"* is defined as how well a utility anticipates, prepares for, mitigates, and recovers from effects of extraordinary events (such as wildfires, earthquakes, cyberattacks, and other potential high impact, low probability (HILP) events) which can have widespread impact on its ability to serve customers. This definition is consistent with IEEE PES-TR65 "*The Definition of Quantification of Resilience*" (April 2018).

[11] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item D.

[12] Quanta Technology is an expertise-based, independent technical consulting and advisory services company specializing in the electric power and energy industries.

3.0 Methodology

In order to compare the impact of the ASP to the current Valley South System configuration[13] on a technical basis, a time-series power flow analysis was performed using the GE-PSLF (Positive Sequence Load Flow) analysis software. PSLF is commonly used by power system engineers throughout the utility power systems industry, including many of the California utilities and the CAISO, to simulate electrical power transmission networks and evaluate system performance.

Models for the existing Valley South System and the proposed ASP[14], were developed in the PSLF software tool. An 8,760-hour load profile was used to simulate the annual forecasted load and power flows in each of the models, and identified thermal overload and voltage violations based on the following analysis criteria, which are consistent with SCE standards[15].

- No potential for N-0 transformer overloads in the system.
- Voltage remains within 95%-105% of nominal system voltage under N-0 and N-1 operating configurations.
- Voltage deviations remain within established limits of +/-5% post contingency.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.

For each hour analyzed, the model determines how much, if any, load is required to be transferred to an adjacent system (if system tie-line capacity is available) or dropped (if system tie-line capacity is not available) to maintain the system within the specified operating limits. The dropped (or unserved) load is summed over the 8,760 hours of the simulation for each year, for base (N-0) and (N-1, or N-2) contingencies[16]. The calculated unserved load is then used to calculate the specific metrics described below. Results for both 10-year and 30-year horizons[17] are presented in this response to assess both near-term and long-term reliability impacts of the proposed ASP.

4.0 Definition of Metrics

The performance of each system configuration was evaluated using the following reliability and resiliency metrics:

- Load at Risk (LAR)
    - Quantified by the number of megawatt-hours (MWh) at risk during thermal overload and voltage violation periods.
    - Calculated for N-0 and all possible N-1 contingencies.
    - For N-1 contingencies, credits the available system tie-line capacity that can be used to reduce LAR.
- Maximum Interrupted Power (IP)

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[13] For purposes of this comparison, the current configuration of the Valley South System includes the Valley-Ivyglen 115 kV Line Project (VIG) and the Valley South 115 kV Subtransmission Line Project (VSSP), both of which are in construction and anticipated to be completed in 2022 and 2021 respectively. See Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018) and Valley South 115 kV Subtransmission Project ("VSSP") CPUC Decision 16-12-001 (issued December 1, 2016).

[14] The ASP PSLF model includes both the new Alberhill System, and the Valley South System with the required modifications to implement the ASP. This allows the PSLF model to evaluate the performance of the entire Valley South System Electrical Needs Area with and without the ASP.

[15] See Southern California Edison Subtransmission Planning Criteria and Guidelines, September 24, 2015.

[16] N-0 refers to operating conditions when all facilities are in-service. N-1 refers to operating conditions when a single subtransmission system component is out-of-service. N-2 refers to operating conditions when two subtransmission system components are simultaneously out-of-service.

[17] These horizons correspond to the 10-year and 30-year load forecasts which project future load in the Valley South System in 2028 and 2048, respectively. See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A for the 10-year forecast, and DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C for the 30-year load forecast.

- Maximum power that would be required to be curtailed during thermal overload and voltage violation periods.
  - Calculated for N-0 and N-1 contingencies.
- Flexibility 1 (Flex-1)
  - Accumulation of LAR for all possible N-2 line contingencies.
  - Credits the available system tie-line capacity that can be used to reduce LAR.
  - Results for each N-2 contingency simulation are probabilistically weighted to reflect the actual frequency of occurrence of N-2 contingencies.
- Flexibility 2 (Flex-2)
  - Flex-2-1
    - Amount of LAR in the Valley South System under a complete Valley Substation outage condition (loss of all transformers at Valley Substation) due to a high impact, low probability event.
    - LAR accumulated over a two-week period that is assumed to occur randomly throughout the year. The two-week recovery period is the minimum expected time to deliver, install, and in-service a remotely stored spare Valley System transformer and to repair associated bus work and other damage.
    - Credits the available system tie-line capacity that can be used to reduce LAR.
  - Flex-2-2
    - Amount of LAR under a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other.
    - The bus work and other substation auxiliary equipment are assumed to remain unaffected, so the Valley Substation spare transformer is assumed to be available to serve load in the Valley South System.
    - The coincident transformer outages are assumed to occur randomly throughout the year and to have a two-week duration – the estimated time to deliver, install, and in-service the remotely stored spare Valley transformers to restore full transformation capacity to Valley South.
    - Observe 1 hour (Short-Term Emergency Load Limit) of 896 megavolt-amperes (MVA)[18] (160% of the 560 MVA transformer nameplate rating). Following this, 24-hour rating (Long-Term Emergency Loading Limit) rating of 672 MVA (120%).
    - Credits the available system tie-line capacity that can be used to reduce EENS.
- Period of Flexibility Deficit (PFD)
  - Maximum number of hours when the available flexibility capacity offered by system tie-lines was less than the required, resulting in LAR.
  - Calculated for N-0 and N-1 contingencies.

Note that these metrics represent future projections of system performance, and the results of each system configuration should be reviewed relative to the other.

5.0 Results

The attached Quanta Technology report demonstrates that the ASP provides substantial benefit relative to the current Valley South System configuration. The study compares the performance of the Valley South System in its current configuration to the performance of the system after implementing the ASP using forward-looking, quantitative, and customer-benefit driven metrics.

[18] For simplicity, within this document it is assumed that MW = MVA.

Table 1 shows the results for each of the metrics described above for the years 2028 and 2048[19] with and without the ASP and demonstrates the positive impact the ASP has on service reliability performance.

Table 1. Service Reliability Performance of the Valley South System with and without the ASP, 2028 and 2048

Metric	Unit	2028		2048	
		Without ASP	With ASP	Without ASP	With ASP
LAR N-0	MWh	250	0	6,310	3[20]
LAR N-1	MWh	67	0	2,823	202
Flex-1	MWh	163,415	30,438	526,314	136,664
Flex-2-1	MWh	3,485,449	39,532	4,060,195	87,217
Flex-2-2	MWh	72,331	0	155,780	100
IP N-0	MW	65	0	288	2
IP N-1	MW	11	0	68	24
PFD N-0	Hours	7	0	77	2
PFD N-1	Hours	32	0	153	14

While the ASP results in substantial improvement in all metrics, the most significant from the perspective of customer impact are the metrics that directly address potential dropped load due to capacity, reliability, and resiliency concerns (i.e., LAR N-0, LAR N-1, Flex-1, Flex-2-1 and Flex-2-2 calculated in units of potential lost MW-hours of service). Table 2 provides comparative results of the cumulative dropped load from the LAR N-0, LAR N-1, Flex-1, Flex-2-1 and Flex-2-2 metrics from 2022[21] through the years 2028 and 2048.

Table 2 – Total Cumulative Load at Risk of Being Dropped with and without the ASP, 2028 and 2048

Metric Category	Metric	2022 – 2028			2022 - 2048		
		Without ASP (MWh)	With ASP (MWh)	*% Reduction*	Without ASP (MWh)	With ASP (MWh)	*% Reduction*
Capacity	LAR N-0	971	0	*100.0%*	56,581	6	*99.9%*
	LAR N-1	274	0	*100.0%*	21,373	1,047	*95.1%*
Reliability & Resiliency	Flex-1	762,859	103,783	*86.4%*	7,841,596	1,817,470	*76.8%*
	Flex-2-1	23,907,934	245,766	*99.0%*	100,091,707	1,545,650	*98.5%*
	Flex-2-2	450,142	0	*100.0%*	2,788,436	432	*99.9%*

Through 2048, the ASP effectively eliminates the capacity (99.9% reduction in LAR N-0) concerns and substantially addresses the reliability concerns associated with line failures (76.8% reduction in Flex-1), and substantially mitigates the resiliency concerns associated with loss of transformers serving the Valley South System (98.5% and 99.9% reductions in Flex-2-1 and Flex-2-2, respectively).

Other key highlights of the projected service reliability performance for the area served by the

[19] These dates represent the end of the 10 year and 30 year horizon starting in 2018, respectively, which are consistent with the load forecast addressed in other data responses. See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A and DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item G.

[20] The 3 MWh of LAR N-0 in 2048 is caused by an overload on the Alberhill-Fogarty 115 kV Line (the line is first overloaded in 2046), which is correctable by reconductoring. At no time through 2048 are the ASP transformers overloaded under N-0 conditions.

[21] These metrics begin to accrue coincident with the project need year of 2022, and continue to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

current Valley South System with ASP in service are as follows:

- The ASP eliminates transformer capacity shortfalls under N-0 conditions on the Valley South System transformers over the entire 30-year study horizon.
- The ASP eliminates subtransmission line capacity shortfalls under N-0 conditions until 2046, when the Alberhill-Fogarty 115 kV Line is forecasted to become overloaded.
- The ASP eliminates subtransmission line capacity shortfalls under N-1 conditions until 2038, when the Alberhill-Fogarty 115 kV Line is forecasted to become overloaded. Additional 115 kV lines are overloaded under N-1 conditions in 2043 (Alberhill-Skylark) and 2048 (Auld-Moraga #1). As such, requirements for system planning consistent with SCE's Subtransmission Planning Criteria and Guidelines are met until 2038. These shortfalls could be corrected by reconductoring each of the three lines to restore the subtransmission line loading to within capacity limits.
- The ASP creates system tie-line capacity which significantly improves the reliability and resiliency performance during N-1 and N-2 conditions in the area served by the current Valley South System. As demonstrated by the Flex-1 and Flex-2 metrics, the ASP provides the ability to transfer load between the Valley South System and the Alberhill System during these contingency conditions.

Important notes regarding the projected service reliability performance for the current Valley South System *without* any project in service include:

- The Valley South System transformers are projected to overload by year 2022.
- By 2028, over 250 MWh of LAR are observable in the system under N-0 conditions. This extends to 6,310 MWh by 2048 with no project in service.
- Between 2028 and 2048, the flexibility deficit duration in the system increases from 7 hours to 77 hours under N-0 conditions.

A Appendix: Quanta Reliability Analysis

The Quanta Technology *Reliability Analysis of Alberhill System Project, Version 2.1 (Second Amended Motion)* is attached as Appendix A to this data submittal.

QUANTA
TECHNOLOGY

Report

Reliability Analysis of Alberhill System Project

PREPARED FOR

Southern California Edison
(SCE)

DATE

June 15, 2021
Version 2.1 (Errata)

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VERSION HISTORY:

Version	Date	Description
0.1	11/8/2019	Initial draft
0.2	12/5/2019	Final draft
1	12/20/2019	Final
2	1/27/2021	This revision corrects errors identified in the cost-benefit analysis results. Specifically: • Modifying the treatment of reliability benefits into Load at Risk (LAR) without probability weighting. This includes N-1, Flex -1 and Flex – 2 benefit categories. • Treatment of N-1 and N-2 probabilities associated with events in the Valley South System. • Modifying the definition of Flex-2-1 and Flex-2-2 events to no longer constrain the events that drives the impact to occur at peak summer load conditions. The events now account for varying conditions throughout the years. • Removing consideration for SAIDI, SAIFI and CAIDI from the reliability metrics, which were previously provided for information purposes only.
2.1 (Second Amended Motion)	6/15/2021	This revision corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the reports are unaffected.

EXECUTIVE SUMMARY

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this report is to quantitatively assess the reliability benefits of the ASP.

A comprehensive framework was developed in coordination with SCE to evaluate the performance of the ASP. This evaluation is complemented by the development of load forecasts for the Valley North and Valley South system planning areas. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048).

The benefits were calculated using power-flow studies that evaluate the impact of the load forecast on the Valley South system both without and with the ASP in service. Each of the reliability, capacity, flexibility, and resiliency objectives of the project performance is quantified by service reliability metrics over a 10-year and 30-year planning horizon. Benefits are quantified as the relative performance of the ASP to the baseline for each of the metrics.

The key findings of this study are summarized as follows:

- The peak load forecast identifies a transformer capacity need in the Valley South System by the year 2022 as the load exceeds the Valley South 500/115 kV transformer capacity of 1,120 MVA. The peak demand within the Valley South System is projected to grow from 1,132 MVA in the year 2022 to 1,378 MVA in the year 2048.
- An evaluation of the quantitative metrics demonstrates the benefits of the ASP project in meeting the overall needs in the Valley South System. Key highlights from the ASP project performance across the 10-year (2028) and 30-year (2048) horizons are as follows:
  - Without the ASP in service and under normal operating conditions (N-0 or all facilities in service), the load at risk increases from 250 MWh to 6,300 MWh between the years 2028 and 2048. With the ASP in service, the amount of load at risk is reduced to 3 MWh in 2048.
  - The periods wherein the system observes a shortage in capacity increases from 7 hours by the year 2028 to 77 hours by the year 2048 under normal operating conditions (N-0). With the ASP in service, this is reduced to 2 hours in the year 2048.
  - Without the ASP in service, maintaining adequate N-1 capacity becomes increasingly challenging at higher load levels. The ASP reduces the N-1 capacity risk from 2,800 MWh to 200 MWh by the year 2048.
  - For emergency, unplanned, or planned maintenance events involving the simultaneous outage of two or more sub-transmission circuits in the Valley South system, the availability of tie-lines with the ASP reduces the expected energy unserved by greater than 70%.
  - The ASP provides measurable operational flexibility improvement to address system needs under high impact low probability (HILP) events in the Valley System. The current system configuration does not provide any benefit in this regard due to unavailable system ties.

- The ASP reduces the losses in the system from 52 GWh to 42 GWh in the year 2028 and from 61 GWh to 49 GWh in the year 2048.

Overall, the ASP demonstrated the robustness necessary to address the needs identified in the Valley service territory. By design, the project provides an alternative source of supply into the original Valley South service territory while effectively separating the system with tie-lines. This offers several advantages that can also help overcome the variability and uncertainty associated with the forecast peak load. The available flexibility through system tie-lines provides relief to system operations under both normal system conditions (increasing flexibility for planned maintenance outages) and for abnormal system conditions (unplanned outages) such as N-1, N-2, and HILP events that affect the region.

The findings and results reported in this document are based on publicly available information and the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

TABLE OF CONTENTS

List of Figures

List of Tables

1 INTRODUCTION

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses of the capacity and reliability needs in the Valley South 500/115 kV system. The objective of this analysis is to evaluate the forecasted impacts of the ASP on service reliability performance utilizing a combination of power flow simulations and service reliability metrics where applicable.

In this section of the report, the project background, scope of work, study objective (including task breakdown), and study process have been outlined.

1.1 Project Background

Valley Substation is a 500/115 kV substation that serves electric demand in southwestern Riverside County. Valley Substation is split into two distinct 500/115 kV electrical systems: Valley North and Valley South. Each is served by two 500/115 kV, 560 MVA, three-phase transformers. The Valley South system is not supplied by any alternative means or tie-line. In other words, this portion of the system is radially served by a single point of interconnection from the bulk electric system (BES) which is under the jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility, and resiliency needs of the Valley South system.

The Valley South 115 kV system electrical needs area (ENA) consists of 15 distribution level 115/12 kV substations.

During the most recent forecast developed for peak demand, SCE identified an overload of the Valley South 500/115 kV transformer capacity by the year 2022 under normal operating conditions (N-0). This forecast was developed for extreme weather conditions (1-in-5-year heat storm).[1] SCE has additionally identified the need to provide system ties to improve reliability, resiliency, and operational flexibility.[2] To address these needs, the ASP was proposed. Figure 1-1 provides an overview of the project area. Key features of this project are as follows:

- Construction of a 1,120 MVA 500/115 kV substation (Alberhill Substation).
- Construction of two 500 kV transmission line segments to connect the proposed Alberhill Substation by looping into the existing Serrano–Valley 500 kV transmission line.

[1] 1-in-5-year peak demand adjusted for extreme weather conditions are typically utilized for system planning involving the sub-transmission system.

[2] Flexibility or Operational Flexibility are used interchangeably in the context of this study. It is considered as the capability of the power system to absorb disturbances to maintain a secure operating state. It is used to bridge the gap between reliability and resiliency needs in the system and overall planning objectives. Typically, system tie-lines allow for the operational flexibility to maintain service during unplanned equipment outages, during planned maintenance and construction activities, and to pre-emptively transfer load to avoid loss of service to affected. customers. System tie-lines can effectively supplement transformation capacity by allowing the transfer of load to adjacent systems.

- Construction of approximately 20 miles of 115 kV sub-transmission lines to modify the configuration of the existing Valley South System to allow for the transfer of five 115/12 kV distribution substations from the Valley South System to the new Alberhill System and to create 115 kV system tie-lines between the two systems.

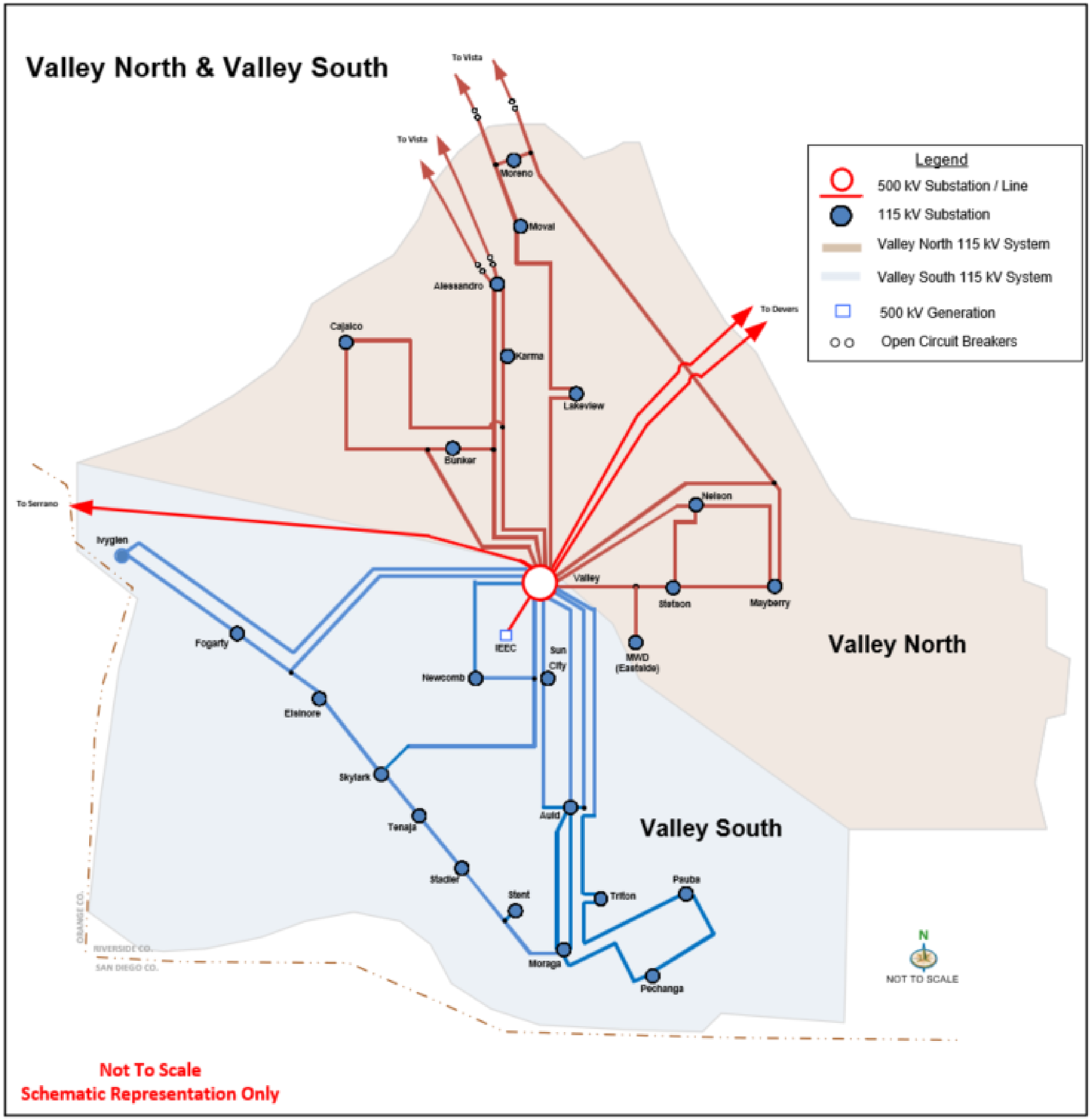

Figure 1-1. Valley Service Areas[3]

[3] Valley-Ivyglen and VSSP 115 kV line projects included.

SCE subsequently submitted an application to the CPUC seeking a Certificate of Public Convenience and Necessity (CPCN). During the proceedings for the ASP, the CPUC requested additional analyses to justify the peak demand forecasts and reliability cases for the project. The CPUC also requested a comparison of the proposed ASP to other potential system alternatives that may satisfy the stated project needs; the alternatives include but are not limited to energy storage, demand response, and distributed energy resources (DERs).

Quanta Technology supported SCE's intent to supplement the existing record in the CPUC proceeding for the ASP utilizing a comprehensive reliability assessment framework. The scope of this assessment included the following:

1. Quantifying the needs in the Valley South 500/115 kV System using the applicable load forecast.
2. Using power flow simulations and quantitative review of project data to evaluate the forecasted impact of proposed ASP on the Valley South System needs.
3. Applying the load forecast to analyze service reliability performance benefits provided by the ASP in the Valley South System.

1.2 Report Organization

In order to provide a comprehensive view of the study methodology, findings, and conclusions, this report has been separated into three sections.

Section 2 of this report introduces the reliability assessment framework while describing the tools, formulation, and overall methodology. The proposed performance metrics are introduced, and their applicability has been described. Section 2.4 presents the forecasted performance of the ASP using the metrics. Section 3 serves as the conclusion.

2 RELIABILITY ASSESSMENT FRAMEWORK AND RESULTS

2.1 Introduction

The objective of this analysis is to evaluate the performance and benefits of the ASP in comparison to the baseline scenario (i.e., no project in service). The performance of the baseline system is initially presented, followed by the ASP. Within the framework of this analysis, reliability, capacity, operational flexibility, and resiliency benefits have been quantified.

In order to successfully evaluate the benefits of a potential project in the Valley South System, its performance must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance,
2. To compare project performance to the baseline scenario (no project in service),
3. To establish a basis to value the performance of the ASP against overall project objectives,
4. To take into consideration the benefits or impacts of flexibility and resiliency (high-impact, low-probability events), and
5. To guide comparison of the projects against the alternatives.

Within the scope of the developed metrics, the following key project objectives are addressed:

<u>Capacity</u>

- Serve current and long-term projected electrical demand requirements in the SCE ENA.
- Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through not only the 10-year planning horizon but also that of a longer-term horizon that identifies needs beyond 10 years, which would allow for an appropriate comparison of alternatives that have different useful lifespan horizons.

<u>Reliability</u>

- Provide safe and reliable electrical service consistent with SCE's Subtransmission Planning Criteria and Guidelines.
- Increase electrical system reliability by constructing a project in a location suitable to serve the ENA (i.e., the area served by the existing Valley South system).

<u>Operational Flexibility and Resiliency</u>

- Increase system operational flexibility and maintain system reliability (e.g., by creating system ties that establish the ability to transfer substations from the current Valley South system and to address both normal condition capacity and N-1 capacity needs).

2.2 Study Methodology

In order to develop a framework to effectively evaluate the performance of a project, the overall study methodology was broken down into the following elements:

1. Develop metrics to establish project performance.
2. Quantify the project performance using commercial power flow software.

Each of the above areas is further detailed throughout this chapter. Since the focus of this analysis is the Valley South system, all discussions are pertinent to this study area.

2.2.1 Study Inputs

SCE provided Quanta Technology with information pertinent to the Valley South, Valley North, and ASP systems. This information encompassed the following data:

1. GE PSLF[4] power flow models for Valley South and Valley North Systems.
    a. 2018 system configuration (current system).
    b. 2021 system configuration (Valley-Ivyglen[5] and VSSP[6] projects modeled and included).
    c. 2022 system configuration (with the ASP in service).
2. Substation layout diagrams representing the Valley Substation.
3. Impedance drawings for the Valley South and Valley North Systems depicting the line ratings and configurations.
4. Single-line diagram of the Valley South and Valley North Systems.
5. Contingency processor tools to develop relevant study contingencies to be considered for each system configuration
6. 8,760 load shape of the Valley South System.
7. Metered customer information per substation (customer count).

The reliability assessment utilizes the spatial load forecast developed for Valley South and Valley North service territories to evaluate the performance of the system for future planning horizons. The developed forecast includes the effects of future developments on photovoltaic projects or installations, electric vehicles, energy efficiency, energy storage, and load modifying demand response as defined in the IEPR 2018 forecast.[7] The representative load forecast is presented in Figure 2-1, which demonstrates system deficiency in the year 2022, where the loading on the Valley South system transformers exceeds maximum operating limits (1,120 MVA).

[4] General Electric's Positive Sequence Load Flow (PSLF) program.

[5] Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018).

[6] VSSP (Valley South 115 kV Sub-transmission Project) CPUC Decision 16-12-001 (issued December 1, 2016).

[7] California Energy Commission, "2018 Integrated Energy Policy Report," 2018.

Benefits begin to accrue coincident with the project need year of 2022. For this assessment, it is assumed that the ASP will be in service by this year and that benefits accrue from 2022 to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

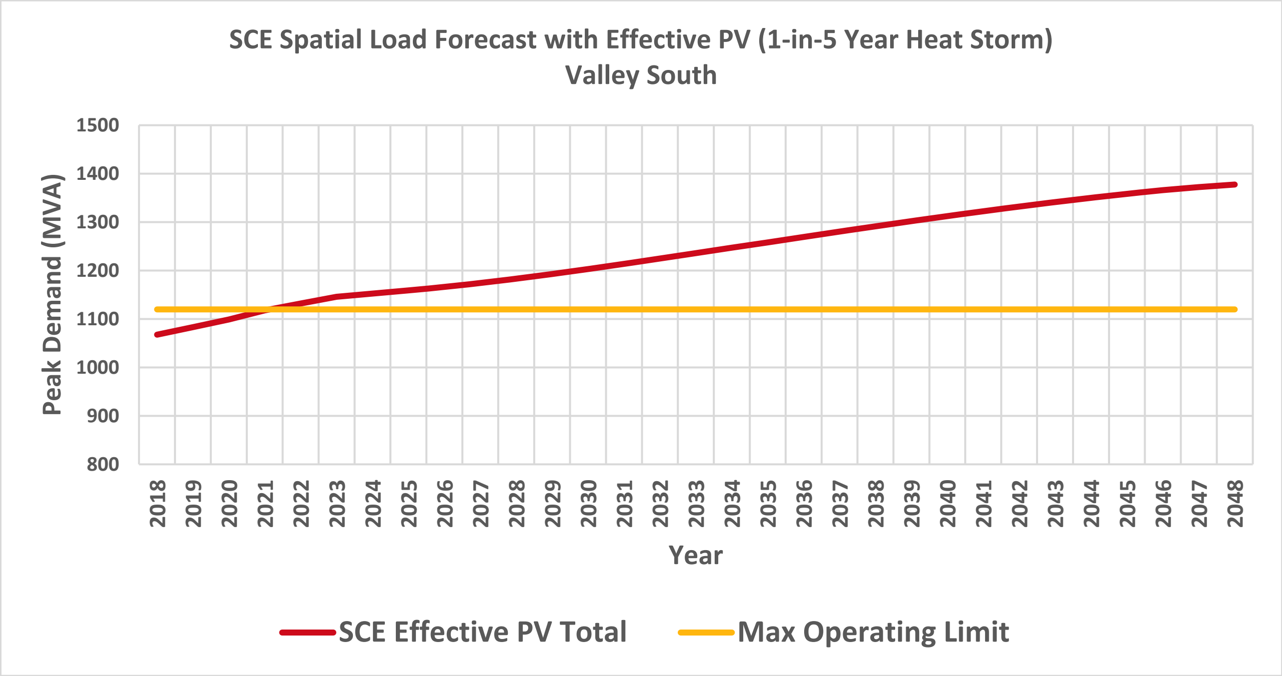

Figure 2-1. Valley South Load Forecast (Peak MVA)

System configuration for the years 2018, 2021, and 2022 are depicted in Figure 2-2 through Figure 2-4.

The load shape of the year 2016 was selected for this study. This selection was made because it demonstrates the largest variability among available records.[8] This load shape is presented in Figure 2-5.

[8] Note that the load shapes of years 2017 and 2018 were skewed due to the use of the AA-bank spare transformers as overload mitigation. Therefore, the load shape for year 2016 was adopted. Its shape is representative only and does not change among years.

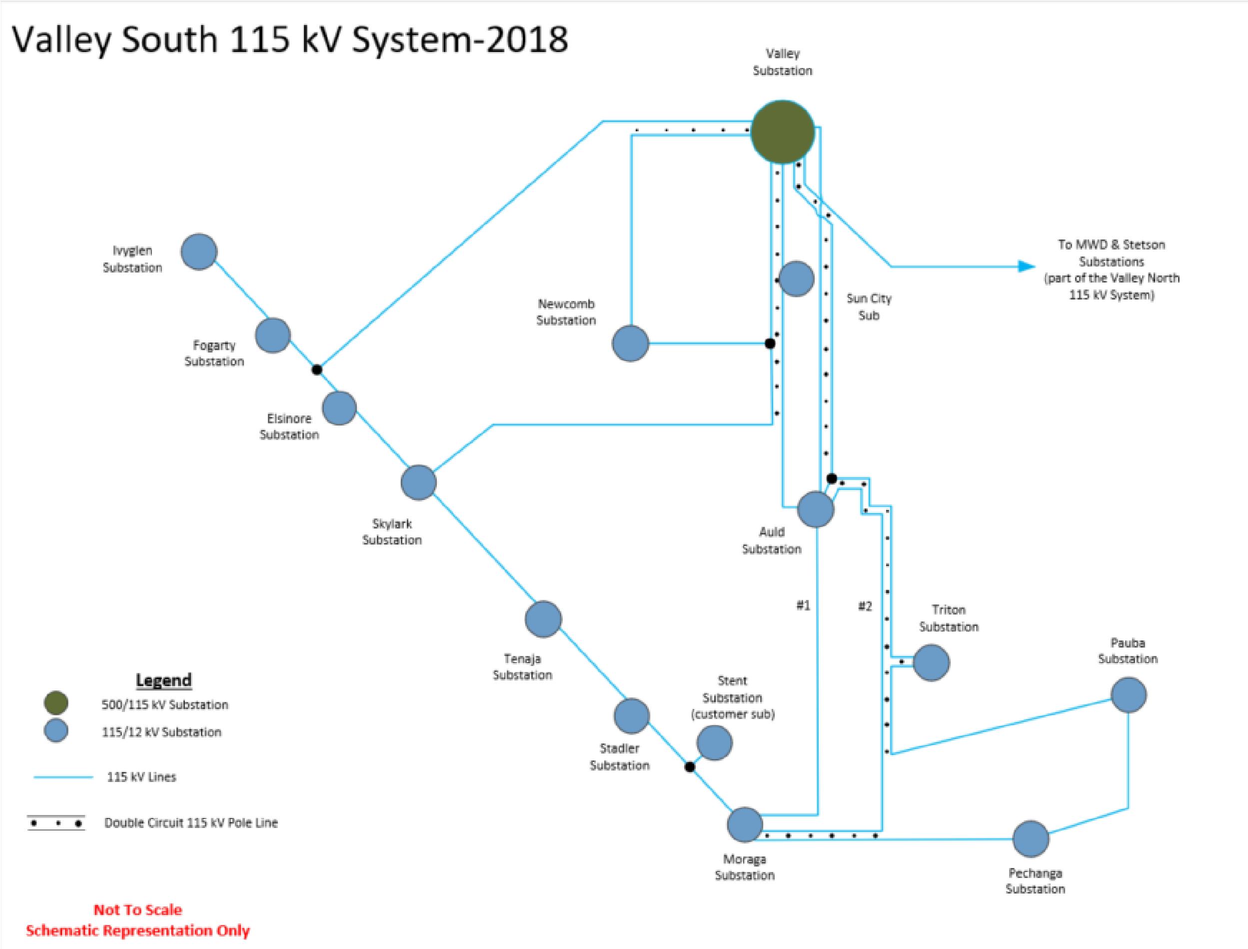

Figure 2-2. Valley South System Configuration (2018)

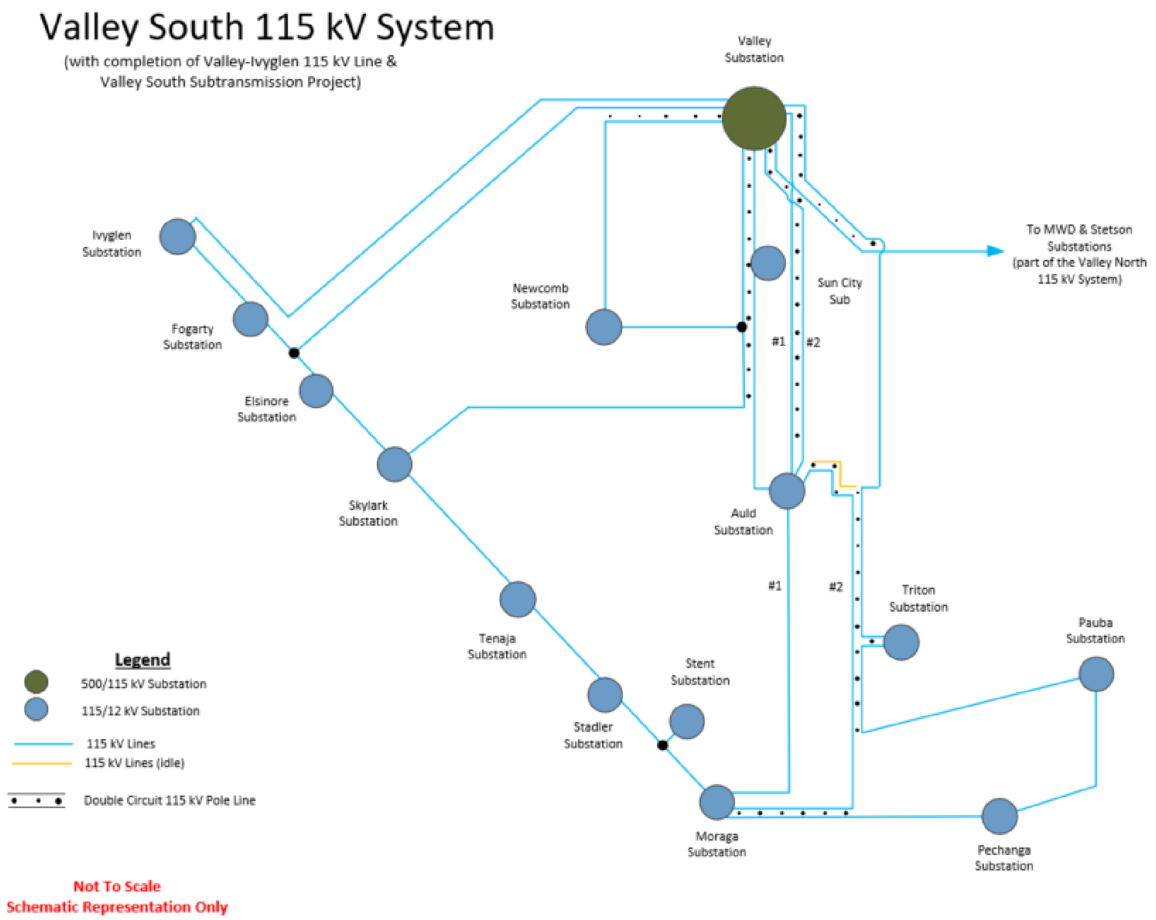

Figure 2-3. Valley South System Configuration (2021)

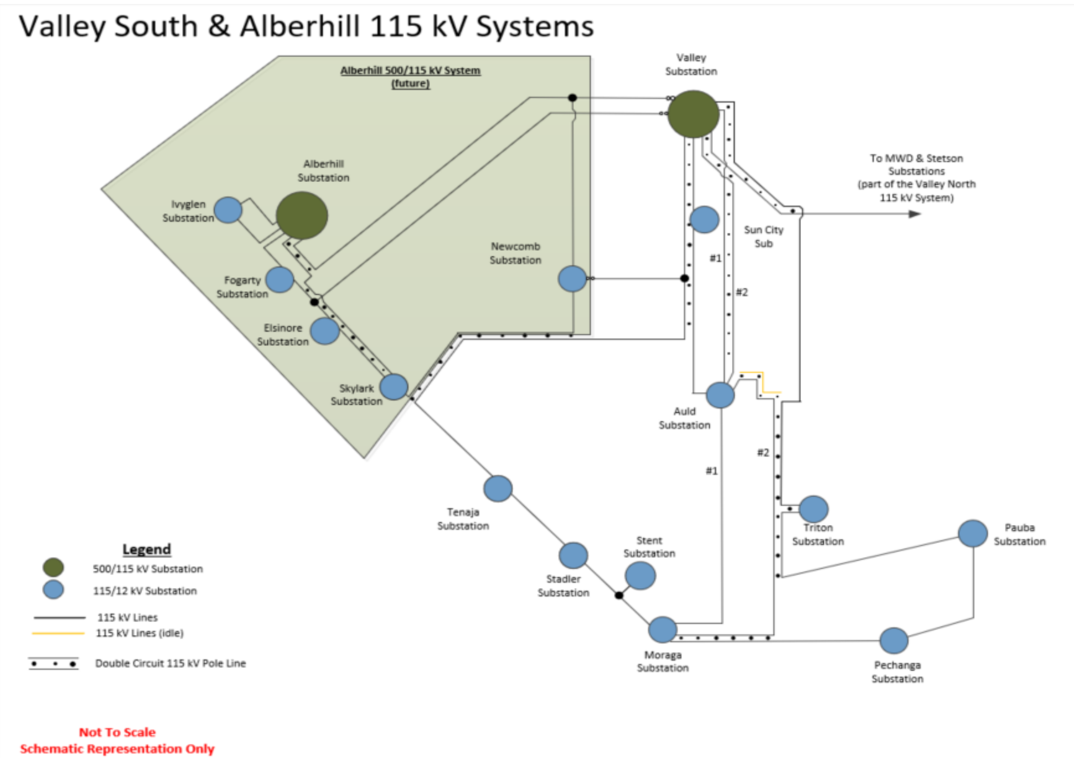

Figure 2-4. Valley South System Configuration (2022 with the ASP in service)

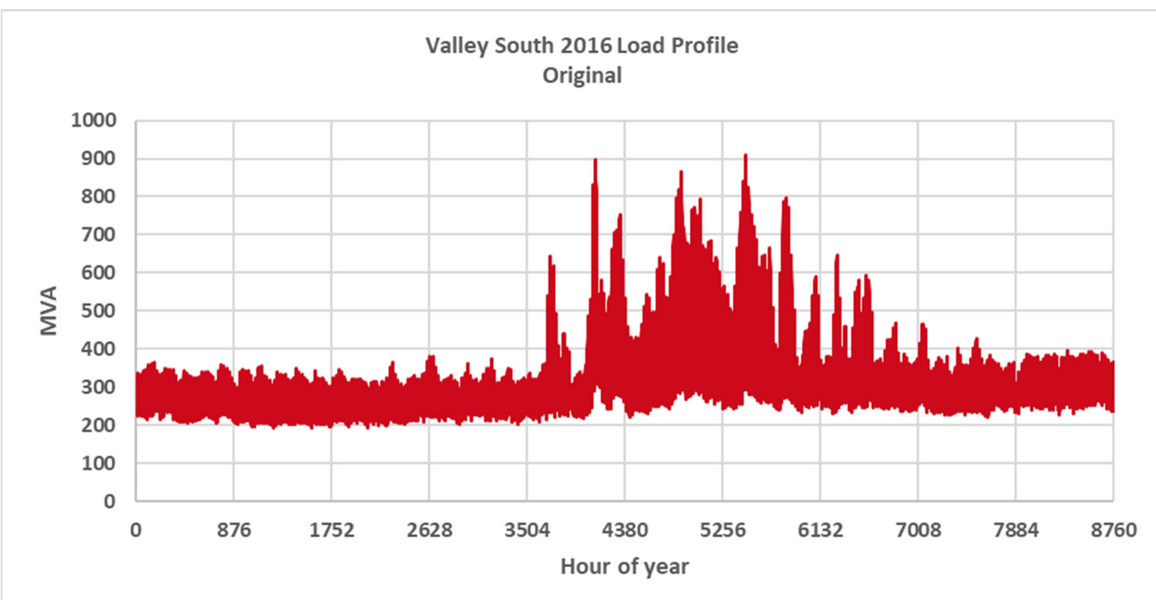

Figure 2-5. Load Shape of the Valley South Substation

2.2.2 Study Criteria

The following guidelines have been used through the course of this analysis to ensure consistency with SCE planning practices:

- The study and planning of projects adhered to SCE's Subtransmission Planning Criteria and Guidelines. Where applicable, North American Electric Reliability (NERC) and Western Electricity Coordinating Council (WECC) standards have been used, especially while taking into consideration the impact on the BES and the non-radial parts of the system under CAISO control.
- Transformer overload criteria established per SCE Subtransmission Planning Criteria and Guidelines for AA banks have been utilized.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 (normal) and N-1 (emergency) operating conditions.
- Voltage limits of 0.95–1.05 per unit (pu) under N-0 and N-1 operating configurations.
- Voltage deviation within established limits of ±5% post contingency.

2.2.3 Reliability Study Tools and Application

A combination of power flow simulation tools has been used for this analysis (i.e., GE PSLF and PowerGem TARA). GE PSLF has been used for base-case model development, conditioning, contingency development, and drawing capabilities. TARA has been used to perform time-series power-flow analysis.

Time-series power-flow analysis is traditionally used in distribution system analysis to assess variation of various quantities over time with changes in load, generation, transmission-line status, etc. It is now finding common application even in transmission system analysis, especially when the system under study is not heavily meshed (radial in nature).

In this analysis, the peak load MVA of the load shape has been adjusted (scaled) to reflect the peak demand for each future year under study. This is represented by Figure 2-6 for the Valley South System as an example. The MW peak load is then distributed amongst the various load models in the Valley Substation in proportion to their MW-to-peak-load ratio in the base case. Load centers under consideration in this analysis of the Valley South and Valley North Systems are listed in Table 2-1.

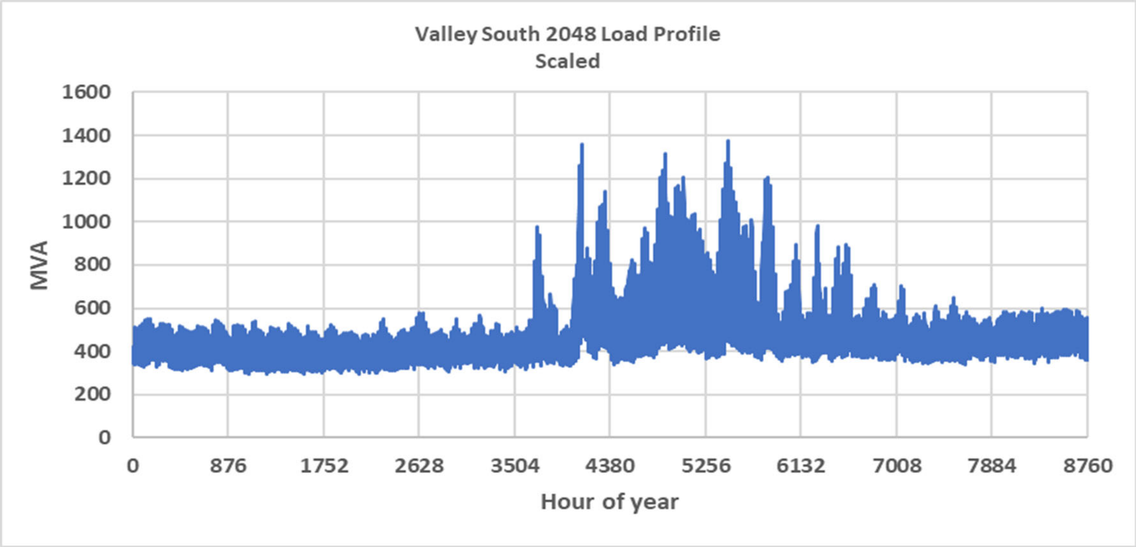

Figure 2-6. Scaled Valley South Load Shape Representative of Study Years

Table 2-1. Distribution Substation Load Buses

Valley South	Valley North
Auld	Alessandro
Elsinore	Bunker
Fogarty	Cajalco
Ivyglen	ESRP_MWD
Moraga	Karma
Newcomb	Lakeview
Pechanga	Mayberry
Pauba	Moreno
Skylark	Moval
Stadler	Nelson
Stent	Stetson
Sun City	
Tenaja	
Triton	

The hourly study (i.e., 8,760 simulations per year) was conducted in selected years (5-year periods from 2022 including 2027, 2032, 2037, 2042, and 2048). The results for years in between were interpolated.

For each simulation, the AC power-flow solution is solved, relevant equipment is monitored under N-0 conditions (normal) and N-1 analysis (emergency), potential reliability violations are recorded, and performance reliability metrics (as described in Section 2.2.4) are calculated. A flowchart of the overall study process is presented in Figure 2-7.

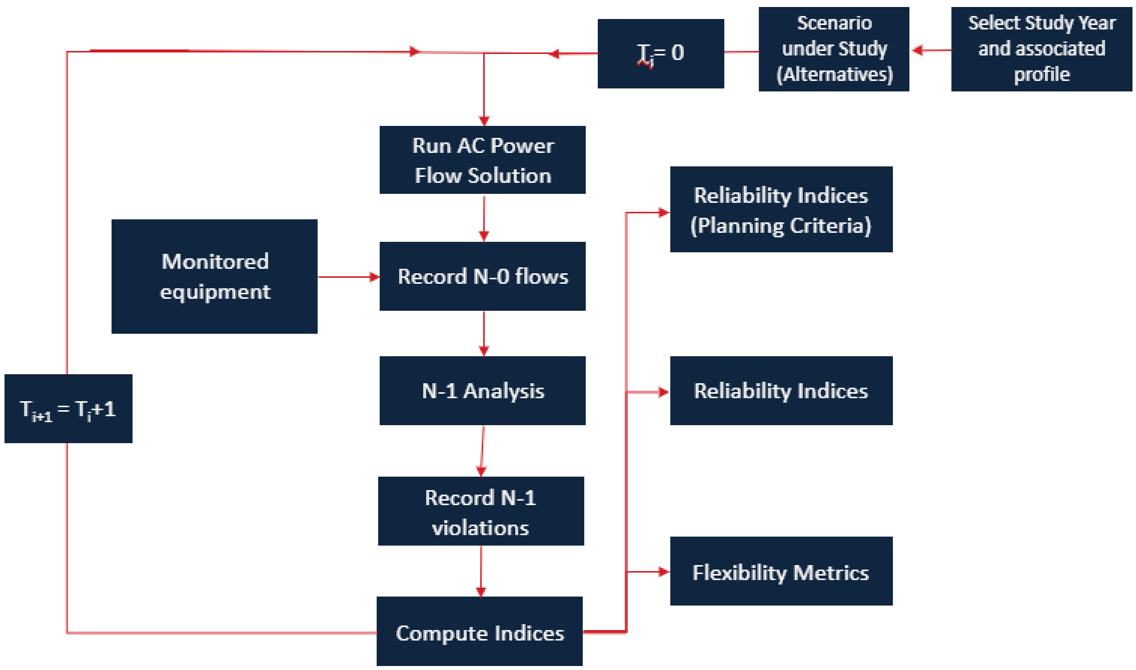

Figure 2-7. Flowchart of Reliability Assessment Process

Unless otherwise specified, all calculations performed under the reliability analysis compute the load at risk, which is not a probability-weighted metric.

In the reliability analysis, the N-1 contingency has been evaluated for every hour of the 8,760 simulations, and all outages are considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates single circuit outages for all sub-transmission lines within the system. Whenever an overload or voltage violation was observed, the binding constraint was applied to the computation of the relevant reliability metric. When the project under evaluation has system tie-lines that can be leveraged, they are engaged to minimize system impacts.

Several flexibility metrics were developed to evaluate the incremental benefits of system tie-lines under emergency or planned/unplanned outages and high-impact, low-probability (HILP) events in the Valley South System.

The Flexibility-1 metric evaluates the system under N-2 (double line outage) conditions, which is representative of combinations of lines switched out for service. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates double-circuit outages for all sub-transmission lines that share a common structure. The objective of this metric is to gauge the incremental benefits that projects provide for events that would traditionally result in unserved energy in the Valley South System. The flow chart in Figure 2-8 presents the overall process. The analysis is initiated taking into consideration the peak loading day (24-hour duration) and applying the N-2 contingencies at each hour. Whenever an overload or voltage violation was observed, the binding constraint is used to determine the MWh load at risk. The results were compared against the baseline system and utilized as the common denominator to scale other days of the year for aggregation into the flexibility metric. When the project under evaluation has tie-lines, they are considered to minimize system impacts.

The Flexibility-2 metric evaluates the project performance under HILP events in the Valley South System. This has been broken down into two components that consider different events impacting the Valley South ENA. Both components utilize a combination of power flow and load profile analysis to determine the amount of load at risk:

- The Flexibility 2-1 metric evaluates the impact of the entire Valley Substation out of service, wherein all the load served by Valley Substation is at risk. Considering a 2-week event (assumed substation outage duration to fully recover from an event of this magnitude), the average amount of load at risk is determined. Utilizing power flow simulations to evaluate the maximum load that can be transferred by projects using system ties, the amount of load that can be recovered is estimated.
- The Flexibility 2-2 metric evaluates a condition wherein Valley South System is served by a single transformer (i.e., two load-serving transformers at Valley Substation are out of service). This scenario is a result of a catastrophic failure (e.g., fire or explosion) of one of the two normally load-serving transformers, and causing collateral damage to the adjacent transformer, rendering both transformers unavailable. Under these conditions, the spare transformer is used to serve a portion of the load. Using the 8,760-load shape and the transformer short-term/long-term emergency loading limits (STELL/LTELL), the average amount of MWh load at risk is estimated and aggregated considering a 2-week duration (mean time to repair under major failures). The analysis accounts for the incremental relief offered by solutions with permanent and temporary load transfer using system ties.

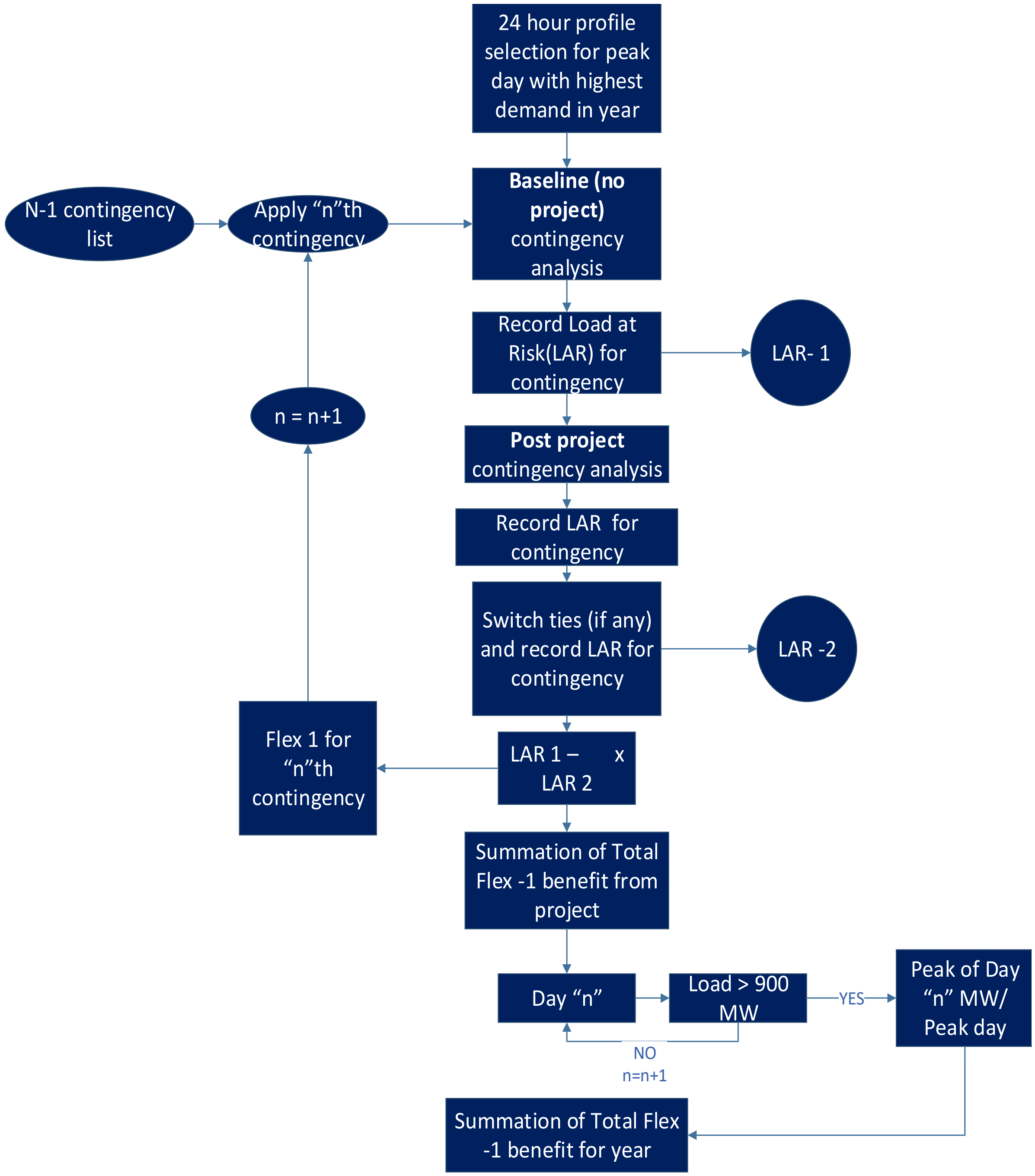

Figure 2-8. Flowchart of Flexibility Metric 1 (Flex 1) Calculation Process

2.2.4 Reliability Metrics

Before introducing reliability metrics, the key elements of the overall project objectives must be outlined to provide direction and to guide further analysis. The treatment of the following is consistent with applicable NERC guidelines and standards for the BES:

- Reliability has been measured with reference to equipment rating (thermal overload) and voltage magnitude (low voltages).
- Capacity represents the need to have adequate resources to ensure that the electricity demand can be met without service outages. Capacity is evaluated under normal and emergency system conditions, and normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address an emergency, maintenance, and planned outage conditions. Therefore, it is expected to operate the system radially and accommodate flexibility by employing normally open tie(s) and connection(s).
- Resiliency has been viewed as an extension of the flexibility benefits, wherein ties and connections are leveraged to recover load under HILP events in the system.

Building on the overall project objectives, the reliability metrics described in the following subsections have been established.

2.2.4.1 Quantitative Metrics

The following quantitative metrics have been proposed to address the reliability, capacity, flexibility, and resiliency needs of the system:

- **Load at Risk**
  a. This is quantified by the amount of MWh at risk from each of the following elements:
     i. For each thermal overload, the MW amount to be curtailed to reduce loading below ratings. This includes transformers and lines serving the Valley South system.
     ii. For voltage violations, the MW amount of load to be dropped based on voltage sensitivity of the bus to bring voltage within limits. The sensitivity study established ranges of load shed associated with varying levels of post-contingency voltage. For the deviation of 1 pu of voltage from the 0.95 pu limit, 0.5 MW of load shed was identified.
  b. Computed for N-0 events and N-1 events and aggregated over the course of the year.
  c. For N-1 events, tie-lines are used where applicable to minimize the amount of MWh at risk.

- **Maximum Interrupted Power (IP)**
  a. This is quantified as the maximum amount of load in MW dropped to address thermal overloads and voltage violations. In other words, it is representative of the peak MW overload observed among all overloaded elements.
  b. Computed for N-0 events and N-1 events.

- **Losses**: Losses are treated as the active power losses in the Valley South system. New lines introduced by the scope of a project have also been included in the loss computation.

- **Availability of Flexibility in the System**: The measure of the availability of the flexible resource (tie-lines, switching schemes) to serve customer demand. It provides a proxy basis for the amount of additional/incremental flexibility (MWh) the alternative solution provides to the system for maintenance operations, emergency events, or the need to relieve other operational issues. Two flexibility metrics are considered:
  a. Flexibility 1: Capability to recover load for maintenance and outage conditions.
     i. Calculated as the amount of energy not served for N-2 events. The measure of the capability of the project to provide flexibility to avoid certain overloads and violations observable under the traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served utilizing the flexibility attributes of the project.
     ii. Considering the large combination of N-2-line outages that potentially impact the Valley South System, the analysis is limited to only circuits that share a common double circuit pole.

  b. Flexibility 2: Recover load for the emergency condition: Single point of failure Valley South substation and transformer banks.
     i. Flex 2-1: Calculated as the energy unserved when the system is impacted by low probability high consequence events such as the loss of the entire Valley Substation. Projects that establish ties or connections to an adjacent network can support the recovery of load during these events. This event is calculated over an average 2-week period (average restoration duration for events of this magnitude) in the Valley system.

        Flex 2-2: Calculated as the amount of MWh load at risk when the system is operating with a single (spare) transformer at Valley Substation (both transformers are out of service due to major failures). This event is calculated over an average 2-week period in the Valley System. Projects that establish ties or connections to an adjacent network can support the recovery of load during these events.

- **Period of Flexibility Deficit (PFD)**: The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) was less than required, resulting in energy being unserved for a given time horizon and direction.

The above list has been iteratively developed to successfully translate the objectives into quantifiable metrics that provide a basis for project performance evaluation.

2.3 Reliability Analysis of the Baseline System

The baseline system is the no-project scenario within this analysis. It depicts a condition wherein the load grows to levels established by the forecast under the study without any project in service to address the shortfalls in transformer rated capacity. This scenario forms the primary basis for comparison against the ASP performance to evaluate the benefits associated with the project.

The baseline system has been evaluated under the study years 2022 (project need year), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 2.2.4 has been calculated using the study methodology outlined in Section 2.2.3.

2.3.1 System Performance under Normal Conditions (N-0)

Table 2-2 presents the findings from system analysis under N-0 conditions in the system.

Table 2-2. Baseline N-0 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
No Project	**2022**	22	13	2
	2028	250	65	7
	2033	905	120	18
	2038	2212	190	37
	2043	4184	246	53
	2048	6310	288	77

2.3.2 System Performance under Normal Conditions (N-1)

Table 2-3 presents the findings from system analysis under N-1 conditions.

Table 2-3. Baseline N-1 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
No Project	**2022**	10	2	14
	2028	67	11	32
	2033	249	21	54
	2038	679	35	88
	2043	1596	45	120
	2048	2823	68	153

In the baseline system analysis, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the load at risk among other reliability metrics under study (reported for 2022 and beyond). In Table 2-4, only the thermal violations associated with each constraint are reported.

Table 2-4. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Year of Overload
Valley South Transformer	N-0	Base case	2022
Auld to Moraga #1	N-0	Base case	2047
Auld to Moraga #2	N-1	Auld-Moraga #1	2038
Auld to Moraga #1	N-1	Auld-Moraga #2	2022
Valley EFG to Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043
Tap 39 to Elsinore	N-1	Valley EFG-Newcomb-Skylark	2038
Auld to Moraga #1	N-1	Skylark-Tenaja	2048
Skylark to Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033
Valley EFG to Sun City	N-1	Valley EFG-Auld #1	2043
Valley EFG to Auld #1	N-1	Valley EFG-Sun City	2048
Valley EFG to Tap 22	N-1	Valley EFG-Newcomb	2043
Valley EFG to Auld #1	N-1	Valley EFG-Auld #2	2048
Valley EFG to Sun City	N-1	Valley EFG-Auld #2	2043
Auld to Moraga #1	N-1	Valley EFG - Triton	2043
Moraga-Pechanga	N-1	Valley EFG - Triton	2038

2.3.3 Flexibility Metrics

Table 2-5 presents the findings from system analysis for Flex 1 and Flex 2 metrics. The Flex 2 metric results represent the average load at risk during the 2-week recovery period for the defined scenario.

Table 2-5. Flexibility and Resiliency Metrics for the Baseline System

	Year	Flex 1 Load at Risk (MWh)	Flex 2-1 Average Load at Risk (MWh)	Flex 2-2 Average Load at Risk (MWh)
No Project	**2022**	54,545	127,935	2,138
	2028	163,415	133,688	2,774
	2033	254,140	139,702	3,514
	2038	344,864	145,991	4,421
	2043	435,589	151,619	5,294
	2048	526,314	155,733	5,975

2.3.4 System Losses

Table 2-6 presents the aggregated losses from the 8,760 assessment of the Valley South system.

Table 2-6. Losses in the Baseline System

	Year	Losses (MWh)
No Project	**2022**	49,667
	2028	52,288
	2033	54,472
	2038	56,656
	2043	58,840
	2048	61,024

2.3.5 Key Highlights of System Performance

The key highlights of system performance for the baseline system are as follows:

1. Without any project in service, the Valley South transformers are overload by the year 2022 (above maximum transformer ratings).
2. By the year 2028, 250 MWh of the load is observed to be at risk in the system under N-0 conditions. This extends to 6,309 MWh by 2048 with no project in service.
3. Between 2028 and 2048, the flexibility deficit in the system increases from 7 hours to 77 hours under the N-0 condition.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasingly challenging to maintain the system N-1 secure.

2.4 Reliability Analysis of the Alberhill System Project

The ASP has been evaluated under the study years 2022, 2028, 2033, 2038, 2043, and 2048 consistent with the baseline system. Each of the reliability metrics established in Section 2.2.4 has been calculated using the study methodology outlined in Section 2.2.3.

2.4.1 Description of Project Solution

The ASP would be constructed in Riverside County and includes the following components:

1. Construction of a new 1,120 MVA 500/115 kV substation to increase the electrical service capacity to the area presently served by the Valley South 115 kV system.
2. Construction of two new 500 kV transmission line segments to connect the new substation to SCE's existing Serrano–Valley 500 kV transmission line. The total length is 3.3 miles.
3. Construction of a new 115 kV subtransmission line and modifications to existing 115 kV subtransmission lines to transfer five existing 115/12 kV substations (Ivyglen, Fogarty, Elsinore,

Skylark, and Newcomb) presently served by the Valley South 115 kV system to the new 500/115 kV substation. The total length is approximately 20.4 miles.

4. Installation of telecommunications improvements to connect the new facilities to SCE's telecommunications network. The total length is approximately 8.7 miles.

Figure 2-9 presents an overview of the project layout and schematic.

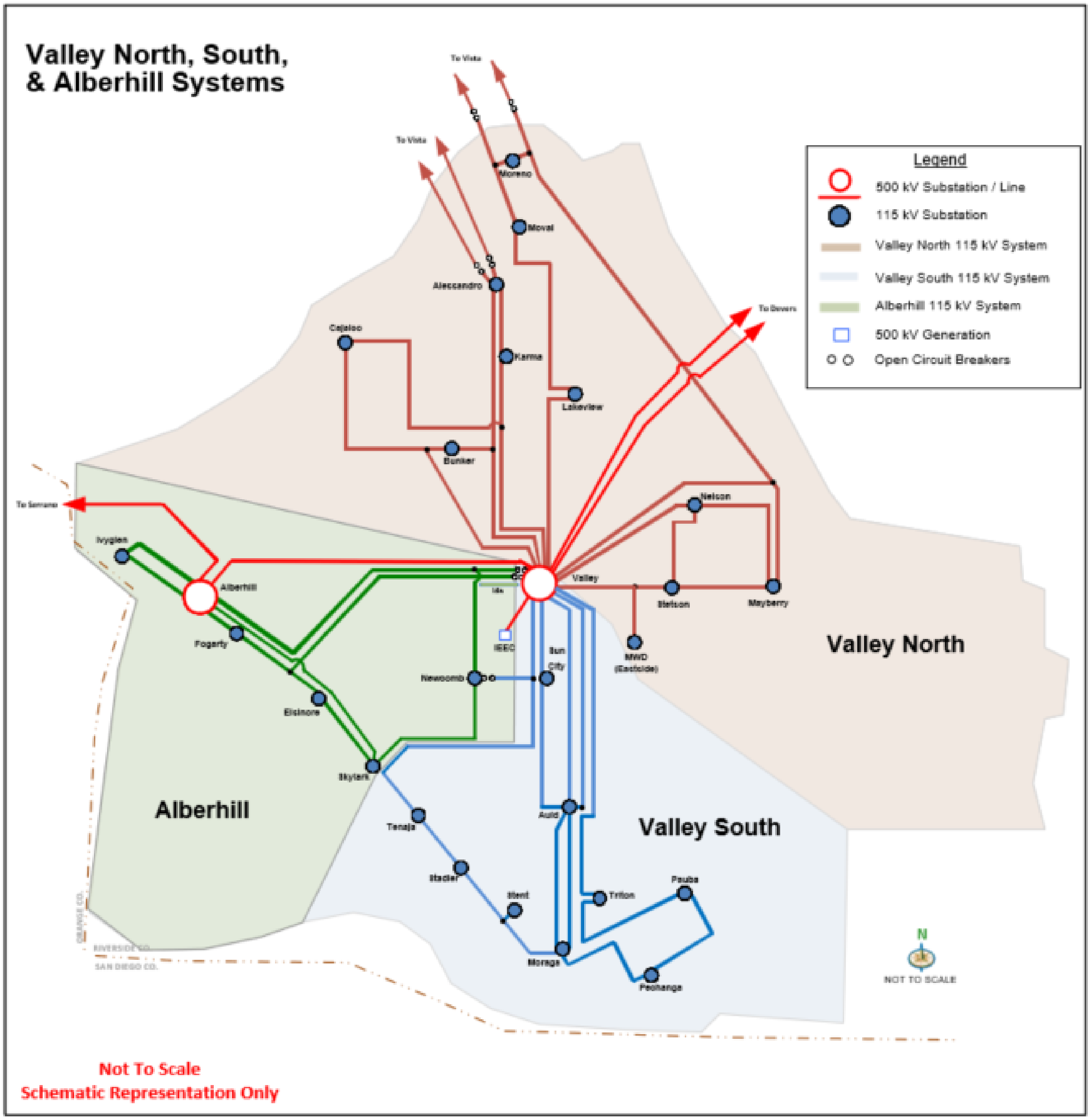

Figure 2-9. Service Territory Configuration after Proposed Alberhill System Project

2.4.2 System Performance under Normal Conditions (N-0)

Table 2-7 presents the findings from system analysis under N-0 conditions.

Table 2-7. Alberhill N-0 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
ASP	**2022**	**0**	**0**	**0**
	2028	0	0	0
	2033	0	0	0
	2038	0	0	0
	2043	0	0	0
	2048	3	2	2

2.4.3 System Performance under Normal Conditions (N-1)

Table 2-8 presents the findings from system analysis under N-1 conditions.

Table 2-8. Alberhill N-1 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
ASP	2022	**0**	**0**	**0**
	2028	0	0	0
	2033	0	0	0
	2038	21	8	4
	2043	84	17	8
	2048	202	24	14

In analyzing the ASP, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the load at risk among other reliability metrics under study (reported for 2022 and beyond).

In Table 2-9 below, only the thermal violations associated with each constraint are reported.

Table 2-9. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Year of Overload
Alberhill to Fogarty	N-0	Base case	2046
Alberhill to Fogarty	N-1	Alberhill–Skylark	2038
Alberhill to Skylark	N-1	Alberhill–Fogarty	2043
Auld to Moraga #1	N-1	Valley EFG–Newcomb–Tenaja	2048

2.4.4 Flexibility Metrics

Table 2-10 present the findings from system analysis for Flex 1 and Flex 2 metrics. The Flex 2 metric results represent the average load at risk during the 2-week recovery period for the defined scenario.

Table 2-10. Flexibility and Resiliency Metrics for the ASP

	Year	Flex 1 Load at Risk (MWh)	Flex 2-1 Average Load at Risk (MWh)	Flex 2-2 Average Load at Risk (MWh)
ASP	2022	0	1,163	0
	2028	30,438	1,516	0
	2033	56,720	1,947	0
	2038	83,001	2,452	0
	2043	109,282	2,954	1
	2048	136,664	3,345	4

2.4.5 System Losses

Table 2-11 presents the aggregated losses from the 8760 assessment of the Valley South and ASP systems.

Table 2-11. Losses in the ASP

	Year	Losses (MWh)
ASP	2022	40,621
	2028	42,671
	2033	44,380
	2038	46,089
	2043	47,797
	2048	49,506

2.4.6 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the study horizon. 3 MWh of load at risk is recorded under N-0 condition in the year 2048 due to an observed overload of the Alberhill–Fogarty 115 kV line.
2. By the year 2038, overloads due to N-1 events will be observable on the Alberhill–Fogarty 115 kV circuit, Alberhill–Skylark 115 kV, and Auld–Moraga 115 kV circuits, which cannot be resolved by potential transfer flexibility.
3. The project provides significant flexibility to address N-1 and N-2 events in the system while also providing significant benefits to address needs under HILP events that occur in the Valley System.

2.5 Evaluation of Quantitative Metrics

The established performance metrics were compared between the baseline and the ASP to quantify the overall benefits accrued over the 10-year and 30-year study horizons calculated at the start of the need year 2022 (i.e., end of 2021). The benefits are quantified as the difference between the baseline and the ASP for each of the metrics and discounted at SCE's weighted aggregate cost of capital (WACC) of 10%. As an example, Figure 2-10 exhibits N-0 load at risk values over the study horizon and its present worth using discount rate of WACC. A similar process was applied to other metrics.

The present worth of *benefits* for reliability metrics over 10-year and 30-year horizons are presented in Table 2-13. The cumulative *benefits* over a 10-year and 30-year horizon are presented in Table 2-12.

The cumulative and present worth of benefits are presented in Appendix C: Reliability Performance Additional Details for both the baseline and the ASP to provide a relative comparison of performance in each reliability category.

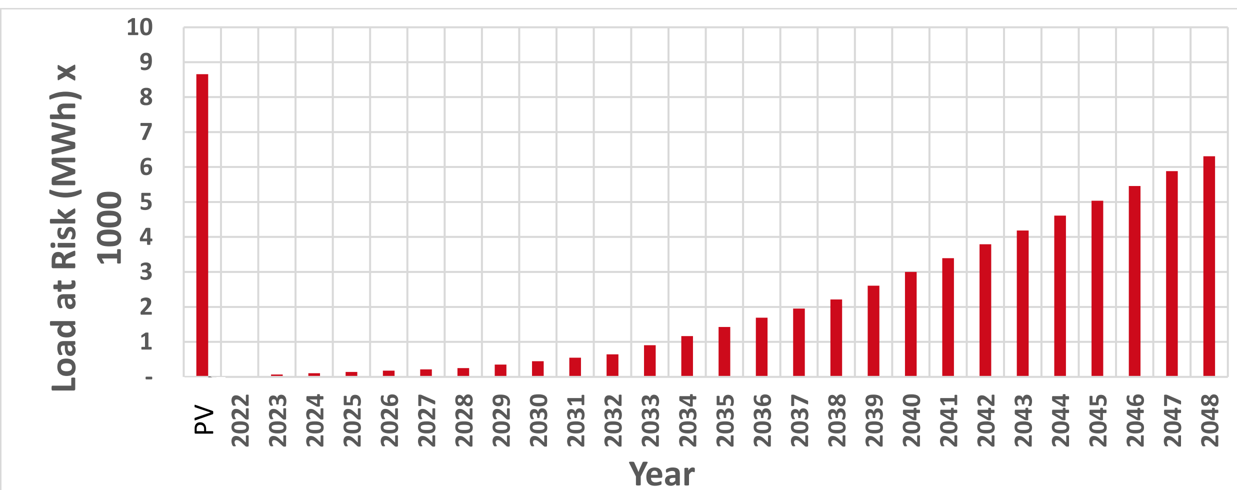

Figure 2-10. N-0 Load at Risk over the Study Horizon and Its PV

Appendix C provides comparative metrics over the 10-year and 30-year horizon between the baseline (no project) and the ASP. These are used to derive the benefits presented in Table 2-12 and (later in Table C-1).

Table 2-12. Cumulative Benefits between Baseline and ASP (10-year and 30-year)

Category	Component	Cumulative Value of Benefits over 10-year horizon (until 2028)	Cumulative Value of Benefits over 30-year horizon (until 2048)
N-0	Losses (MWh)	65,319	277,608
N-1	Load at Risk (MWh)	274	20,326
N-1	IP (MW)	45	601
N-1	PFD (hr)	173	1,907
N-1	Flex 1 Load at Risk (MWh)	659,076	6,024,126
N-1	Flex 2-1 Average Load at Risk (MWh)	907,590	3,779,849
N-1	Flex 2-2 Average Load at Risk (MWh)	17,266	106,937
N-0	Load at Risk (MWh)	971	56,575
N-0	IP (MW)	288	4,053
N-0	PFD (hr)	35	811

Table 2-13. Present Worth of Benefits between Baseline and ASP (10-year and 30-year)

Category	Component	Present Worth of Benefits over 10-year horizon (until 2028)	Present Worth of Benefits over 30-year horizon (until 2048)
N-0	Losses (MWh)	45,254	90,384
N-1	Load at Risk (MWh)	173	2,896
N-1	IP (MW)	28	133
N-1	PFD (hr)	115	420
N-1	Flex 1 Load at Risk (MWh)	434,402	1,438,932
N-1	Flex 2-1 Average Load at Risk (MWh)	629,646	1,243,232
N-1	Flex 2-2 Average Load at Risk (MWh)	11,822	29,195
N-0	Load at Risk (MWh)	606	8,657
N-0	IP (MW)	185	853
N-0	PFD (hr)	23	146

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the ASP. The results for each category of benefits demonstrate the merits of the ASP to complement the increasing reliability, capacity, flexibility, and resiliency needs in the Valley South service area.

3 CONCLUSIONS

SCE retained Quanta Technology to supplement the existing record in the CPUC proceedings for the ASP with additional analyses to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this report is to quantitatively assess the reliability benefits of the ASP.

A comprehensive framework was developed in coordination with SCE to evaluate the performance of the ASP. This evaluation is complemented by the development of load forecasts for the Valley North and Valley South system planning areas. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048).

The benefits were calculated using power flow studies that evaluate the impact of the load forecast on the Valley South System both without and with the ASP in service. Each of the reliability, capacity, flexibility, and resiliency objectives of project performance is quantified by service reliability metrics over a 10-year and 30-year planning horizon. Benefits are quantified as the relative performance of the ASP to the baseline for each of the metrics.

The key findings of this study are summarized as follows:

- The peak load forecast identifies a transformer capacity need in the Valley South system by the year 2022, as the load exceeds Valley South 500/115 kV transformer capacity of 1,120 MVA. The peak demand within Valley South service territory is projected to grow from 1,132 MVA in the year 2022 to 1,378 MVA in the year 2048.
- An evaluation of the quantitative metrics demonstrates significant benefits of the ASP project in meeting overall needs in the Valley South service area. Key highlights from the ASP project performance across the 10-year (2028) and 30-year (2048) horizons are discussed.
    - Without the ASP in service and under normal operating conditions (N-0 or all facilities in service), the load at risk increases from 250 MWh to 6,300 MWh between the years 2028 and 2048. With the ASP in service, the amount of load at risk is reduced to 3 MWh in 2048.
    - The periods wherein the system observes a shortage in capacity increases from 7 hours by the year 2028 to 77 hours by the year 2048 under normal operating conditions (N-0). With the ASP in service, this is reduced to 2 hours in the year 2048.
    - Without the ASP in service, maintaining adequate N-1 capacity becomes increasingly challenging at higher load levels. The ASP reduces the N-1 capacity risk from 2,800 MWh to 200 MWh by the year 2048.
    - For emergency, unplanned, or planned maintenance events involving the simultaneous outage of two or more subtransmission circuits in the Valley South System, the availability of tie-lines with the ASP reduces load at risk by greater than 70%.

- The ASP provides measurable operational flexibility improvement to address system needs under the HILP events in the Valley System. The current system configuration does not provide any benefit in this regard due to unavailable system ties.
- The ASP reduces the losses in the system from 52 GWh to 42 GWh in the year 2028 and from 61 GWh to 49 GWh in the year 2048.

Overall, the ASP demonstrated the robustness necessary to address the needs identified in the Valley service territory. By design, the project provides an alternative source of supply into the original Valley South service territory while effectively separating the system with tie-lines. This offers several advantages that can also help overcome the variability and uncertainty associated with the forecast peak load. The available flexibility through system tie-lines provides relief to system operations under both normal system conditions (increasing flexibility for planned maintenance outages) and for abnormal system conditions (unplanned outages) such as N-1, N-2, and HILP events that affect the region.

Findings and results reported in this document are based on publicly available information and the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

APPENDIX A: GLOSSARY

ASP: Alberhill System Project

BES: Bulk Electric System

CAIDI: Customer Average Interruption Duration Index

CAISO: California Independent System Operator

CPUC: California Public Utility Commission

DER: Distributed Energy Resources

LAR: Load at Risk

NERC: North American Electric Reliability Corporation

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

WECC: Western Electricity Coordinating Council

APPENDIX B: REFERENCES

1. Sub-transmission Planning Criteria and Guidelines, SCE 9/24/2015.
2. Decision Granting Petition to Modify Permit to Construct the Valley-Ivyglen 115 kV Sub-transmission Line Project and Holding Proceeding Open for Certificate of Public Convenience and Necessity for The Alberhill System Project, CPUC 8/31/2018.

APPENDIX C: RELIABILITY PERFORMANCE ADDITIONAL DETAILS

The cumulative benefits over a 10-year and 30-year horizon are presented in Table C-1 and Table C-2, respectively.

The present worth of benefits over a 10-year and 30-year horizon are presented in Table C-3 and Table C-4, respectively.

Table C-1. Cumulative Reliability Performance and Benefits with and without the ASP (10-year)

Category	Component	Cumulative Service Reliability Performance over 10-year Horizon	Cumulative Service Reliability Performance over 10-year Horizon	Cumulative Benefit over 10-year Horizon
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	356,842	291,522	65,319
N-1	Load at Risk (MWh)	274	0	274
N-1	IP (MW)	45	0	45
N-1	PFD (hr)	173	0	173
N-1	Flex 1 Load at Risk (MWh)	762,858	103,783	659,076
N-1	Flex 2-1 Average Load at Risk (MWh)	917,017	9,427	907,590
N-1	Flex 2-2 Average Load at Risk (MWh)	17,266	0	17,266
N-0	Load at Risk (MWh)	971	0	971
N-0	IP (MW)	288	0	288
N-0	PFD (hr)	35	0	35

Table C-2. Cumulative Reliability Performance and Benefits with and without the ASP (30-year)

Category	Component	Cumulative Service Reliability Performance over 30-year horizon (until 2048)	Cumulative Service Reliability Performance over 30-year horizon (until 2048)	Cumulative Benefit over 10-year horizon (until 2048)
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	1,494,322	1,216,714	277,608
N-1	Load at Risk (MWh)	21,684	1,047	20,327
N-1	IP (MW)	780	179	601
N-1	PFD (hr)	1,999	92	1,907
N-1	Flex 1 Load at Risk (MWh)	7,841,596	1,817,470	6,024,127
N-1	Flex 2-1 Average Load at Risk (MWh)	3,839,134	59,285	3,779,849
N-1	Flex 2-2 Average Load at Risk (MWh)	106,954	17	106,937
N-0	Load at Risk (MWh)	56,581	6	56,575
N-0	IP (MW)	4,056	4	4,053
N-0	PFD (hr)	815	4	811

Table C-3. Present Worth of Benefits with and without the ASP (10-year)

Category	Component	Present Worth of Service Reliability Performance over 10-year horizon (until 2028)	Present Worth of Service Reliability Performance over 10-year horizon (until 2028)	Present Worth of Benefits over 10-year horizon (till 2028)
		Baseline	***ASP***	***Baseline – ASP***
N-0	Losses (MWh)	247,375	202,121	45,254
N-1	Load at Risk (MWh)	173	0	173
N-1	IP (MW)	28	0	28
N-1	PFD (hr)	115	0	115
N-1	Flex 1 Load at Risk	497,134	262,732	434,402
N-1	Flex 2-1 Average Load at Risk (MWh)	636,100	6,453	629,646
N-1	Flex 2-2 Average Load at Risk (MWh)	11,822	0	11,822
N-0	Load at Risk (MWh)	606	0	606
N-0	IP (MW)	185	0	185
N-0	PFD (hr)	23	0	23

Table C-4. Present Worth Reliability Performance and Benefits with and without the ASP (30-year)

Category	Component	Present Worth of Service Reliability Performance over 30-year horizon (until 2048)	Present Worth of Service Reliability Performance over 30-year horizon (until 2048)	Present Worth of Benefits over 30-year horizon (until 2048)
		Baseline	***ASP***	***Baseline – ASP***
N-0	Losses (MWh)	490,137	399,753	90,384
N-1	Load at Risk (MWh)	3,054	112	2,896
N-1	IP (MW)	154	21	133
N-1	PFD (hr)	431	11	420
N-1	Flex 1 Load at Risk	1,806,240	368,207	1,438,032
N-1	Flex 2-1 Average Load at Risk (MWh)	1,259,315	16,083	1,243,232
N-1	Flex 2-2 Average Load at Risk (MWh)	29,196	2	29,195
N-0	Load at Risk (MWh)	8,658	0	8,657
N-0	IP (MW)	853	0	853
N-0	PFD (hr)	147	0	147

EXHIBIT F-1 (SECOND AMENDED) REDLINE

Item F:

The forecasted impact of the proposed project on **service reliability performance**, using electric service reliability metrics where applicable.

Response to Item F:

Revision 1.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This Second Amended Motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 1

Revision Date: February 2, 2021

Summary of Revisions:

- Modifies the terminology for the primary metric (previously Expected Energy Not Served (EENS) and now Load at Risk (LAR)) to clarify that the metrics are cumulative values of the potential amount of unserved load and are not probability weighted to associate the frequency and timing of events that would prompt loss of service to customers.
- Deletes the SAIFI, SAIDI and CAIFI metrics to avoid confusion with similar data reported in Supplemental Data Response Items B and C[1] which are calculated on the basis of a different customer base and thus cannot be compared directly. Because these SAIFI, SAIDI and CAIDI values previously provided here were derived from the LAR values they did not provide any additional insight on the effectiveness of the Alberhill System Project in meeting system reliability/resiliency needs.
- Modifies the description of the Flex-1 and Flex-2 metrics to reflect more realistic operation scenarios.

[1] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item C and DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item D.

1.0 Executive Summary

SCE interprets this data request as inquiring about the service reliability performance of the proposed Alberhill System Project (ASP)[2].

The proposed ASP was designed to mitigate the transformer capacity shortfall currently anticipated to occur in the Valley South System as early as 2022, while also addressing the long-standing need for system tie-lines to improve reliability and resiliency by providing the ability to transfer load to adjacent systems for maintenance and other activities (planned outages), and under abnormal system operating conditions (unplanned outages). To evaluate the impact of the proposed project on service reliability performance, the response to this data request uses forward-looking service reliability performance metrics, related to customers and energy at risk due to service interruption, to demonstrate that the ASP meets the identified project needs for capacity, reliability, and resiliency over both short-term (10 year) and long-term (30 year) horizons. These metrics demonstrate that the ASP reduces the customer risk of loss of service due to outages related to capacity, reliability, and resiliency issues by ~~98~~99% through 2028, and by 97% through 2048[3]. These reductions sufficiently improve system performance to comply with SCE's planning standards[4] through 2038, with only one line reconductoring project needed to satisfy these criteria through 2048.

2.0 Introduction

As discussed throughout the ASP Certificate of Convenience and Necessity (CPCN) proceeding (A.09-09-022) and specifically highlighted in an earlier supplemental data request response[5], the reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity[6] margin, configuration, and size that make the Valley South subtransmission system[7] much more vulnerable to future reliability[8] problems than any other Southern California Edison (SCE) subtransmission system. Specifically, in its current status, the Valley South System operates at or very close to its maximum operating limits, has no connections

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[2] Service reliability results for alternatives to the Alberhill System Project, which were studied in the cost benefit analysis described in DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C, can be found in Quanta Technology Report, *Benefit Cost Analysis of Alternatives.*

[3] These percentages capture the projected cumulative percent reduction in unserved customer energy needs for various line and transformer outage contingency conditions (through 2028 and 2048 respectively) that are achieved as a result of ASP being in service.

[4] See Southern California Edison Subtransmission Planning Criteria and Guidelines, September 24, 2015.

[5] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B.

[6] *"Capacity"* is defined as the availability of electric power to serve load and is primarily comprised of two elements in a *radial transmission system*; a lack of capacity of either type will lead to reliability challenges in a radial subtransmission system: (1) "*transformation capacity"* – the ability to deliver power from the transmission system (through substation transformers); and (2) "*subtransmission system line capacity"* – the ability to deliver power to substations which directly serve the customer load in an area. Subtransmission system line capacity also includes "*system tie-line capacity*," which is the ability to transfer load to an adjacent subtransmission system to avoid, and reduce the number of customer's affected by, planned and unplanned outages in the system. Note, a *radial subtransmission system* is one that is provided power from a single source on the transmission system. This is in contrast to a networked system which has multiple transmission and subtransmission source connections. Almost all of SCE's subtransmission systems are of a radial design.

[7] While Southern California Edison typically considers a planning area to be at the substation level, for the purpose of this data request, the discussion herein focuses on the Valley South System, as it is most relevant to the Alberhill System Project proceedings. Certain characteristics discussed here may have broader impacts (on the Valley North System specifically, given the split nature of these systems), but the focus of this response remains on the Valley South System.

[8] *"Reliability"* is defined as a utility's ability to meet service requirements under normal and N-1 contingency conditions, both on a short-term and long-term basis. The ability to meet long-term capacity needs of a given system is an important aspect of reliability. This definition is consistent with IEEE 1366*, "IEEE Guide for Electric Power Distribution Reliability Indices"* which excludes extraordinary events from reliability data reporting.

(system tie-lines) to other systems, and represents the largest concentration of customers on a single substation in SCE's entire system. These characteristics threaten the future ability of the Valley South System to serve load under normal and abnormal conditions.

Also discussed in this proceeding, in the case of a catastrophic event (such as a major fire, earthquake, or incident at Valley Substation), SCE's ability to maintain service or to restore power in the event of an outage is significantly limited by the concentration of source power in a single location at Valley Substation[9]. This characteristic, in combination with others described in this submittal, results in specific concerns for the Valley South System from a resiliency[10] perspective.

In an earlier supplemental data request response[11], SCE provided an analysis of several years of electric reliability performance for the Valley Systems to demonstrate existing customer service metrics. SCE provided data for Valley South (and Valley North) historical reliability metrics (SAIDI and SAIFI) compared to other SCE subtransmission systems. These data show that, to date, the capacity of the Valley South System has been sufficient to serve all system customers under commonly planned for normal and extreme weather conditions. SCE noted that while SAIDI and SAIFI data are the principal metrics used to report on historical system reliability, they are primarily influenced by events at the distribution system level and thus are less informative for planning at the subtransmission system level. This is because when an electric power system has sufficient substation transformer capacity and/or sufficient system tie-line capacity, and is properly maintained and operated, reliability performance is driven largely by random, distribution-level events. Importantly, as SCE stated, the past reliability performance of the Valley Systems is not a driver for the proposed ASP project. Given the limited remaining transformer capacity serving the Valley South System and its lack of system tie-lines, the future reliability performance of the Valley South System will be driven less by random, distribution level events, and more by subtransmission level events that cannot be mitigated due to the lack of capacity margin and/or system tie-lines. These events would otherwise be mitigated by operational flexibility enabled by available transformer and system tie-line capacity to allow for short-term line and transformer overloads (per standards) to be addressed through the transfer of distribution substations to an adjacent system.

This data request response evaluates the Valley South System with and without the ASP and compares the reliability performance of the two system configurations using a set of *forward-looking* reliability and resiliency metrics related directly to SCE's ability to serve customer load throughout this specific electrical needs area. The analysis presented herein was developed and implemented collaboratively between SCE and a contractor, Quanta Technology[12], and documented in the attached report by Quanta Technology (see Appendix A).

[9] The source of power to the Valley South System passes through a single point of delivery at Valley Substation, which is connected to the CAISO-controlled Bulk Electric System at the 500 kV voltage level.

[10] "*Resiliency*" is defined as how well a utility anticipates, prepares for, mitigates, and recovers from effects of extraordinary events (such as wildfires, earthquakes, cyberattacks, and other potential high impact, low probability (HILP) events) which can have widespread impact on its ability to serve customers. This definition is consistent with IEEE PES-TR65 "*The Definition of Quantification of Resilience*" (April 2018).

[11] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item D.

[12] Quanta Technology is an expertise-based, independent technical consulting and advisory services company specializing in the electric power and energy industries.

3.0 Methodology

In order to compare the impact of the ASP to the current Valley South System configuration[13] on a technical basis, a time-series power flow analysis was performed using the GE-PSLF (Positive Sequence Load Flow) analysis software. PSLF is commonly used by power system engineers throughout the utility power systems industry, including many of the California utilities and the CAISO, to simulate electrical power transmission networks and evaluate system performance.

Models for the existing Valley South System and the proposed ASP[14], were developed in the PSLF software tool. An 8,760-hour load profile was used to simulate the annual forecasted load and power flows in each of the models, and identified thermal overload and voltage violations based on the following analysis criteria, which are consistent with SCE standards[15].

- No potential for N-0 transformer overloads in the system.
- Voltage remains within 95%-105% of nominal system voltage under N-0 and N-1 operating configurations.
- Voltage deviations remain within established limits of +/-5% post contingency.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.

For each hour analyzed, the model determines how much, if any, load is required to be transferred to an adjacent system (if system tie-line capacity is available) or dropped (if system tie-line capacity is not available) to maintain the system within the specified operating limits. The dropped (or unserved) load is summed over the 8,760 hours of the simulation for each year, for base (N-0) and (N-1, or N-2) contingencies[16]. The calculated unserved load is then used to calculate the specific metrics described below. Results for both 10-year and 30-year horizons[17] are presented in this response to assess both near-term and long-term reliability impacts of the proposed ASP.

4.0 Definition of Metrics

The performance of each system configuration was evaluated using the following reliability and resiliency metrics:

- Load at Risk (LAR)
    - Quantified by the number of megawatt-hours (MWh) at risk during thermal overload and voltage violation periods.
    - Calculated for N-0 and all possible N-1 contingencies.
    - For N-1 contingencies, credits the available system tie-line capacity that can be used to reduce LAR.
- Maximum Interrupted Power (IP)

[13] For purposes of this comparison, the current configuration of the Valley South System includes the Valley-Ivyglen 115 kV Line Project (VIG) and the Valley South 115 kV Subtransmission Line Project (VSSP), both of which are in construction and anticipated to be completed in 2022 and 2021 respectively. See Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018) and Valley South 115 kV Subtransmission Project ("VSSP") CPUC Decision 16-12-001 (issued December 1, 2016).

[14] The ASP PSLF model includes both the new Alberhill System, and the Valley South System with the required modifications to implement the ASP. This allows the PSLF model to evaluate the performance of the entire Valley South System Electrical Needs Area with and without the ASP.

[15] See Southern California Edison Subtransmission Planning Criteria and Guidelines, September 24, 2015.

[16] N-0 refers to operating conditions when all facilities are in-service. N-1 refers to operating conditions when a single subtransmission system component is out-of-service. N-2 refers to operating conditions when two subtransmission system components are simultaneously out-of-service.

[17] These horizons correspond to the 10-year and 30-year load forecasts which project future load in the Valley South System in 2028 and 2048, respectively. See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A for the 10-year forecast, and DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C for the 30-year load forecast.

- Maximum power that would be required to be curtailed during thermal overload and voltage violation periods.
  - Calculated for N-0 and N-1 contingencies.
- <u>Flexibility 1 (Flex-1)</u>
  - Accumulation of LAR for all possible N-2 line contingencies.
  - Credits the available system tie-line capacity that can be used to reduce LAR.
  - Results for each N-2 contingency simulation are probabilistically weighted to reflect the actual frequency of occurrence of N-2 contingencies.
- <u>Flexibility 2 (Flex-2)</u>
  - <u>Flex-2-1</u>
    - Amount of LAR in the Valley South System under a complete Valley Substation outage condition (loss of all transformers at Valley Substation) due to a high impact, low probability event.
    - LAR accumulated over a two-week period that is assumed to occur randomly throughout the year. The two-week recovery period is the minimum expected time to deliver, install, and in-service a remotely stored spare Valley System transformer and to repair associated bus work and other damage.
    - Credits the available system tie-line capacity that can be used to reduce LAR.
  - <u>Flex-2-2</u>
    - Amount of LAR under a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other.
    - The bus work and other substation auxiliary equipment are assumed to remain unaffected, so the Valley Substation spare transformer is assumed to be available to serve load in the Valley South System.
    - The coincident transformer outages are assumed to occur randomly throughout the year and to have a two-week duration – the estimated time to deliver, install, and in-service the remotely stored spare Valley transformers to restore full transformation capacity to Valley South.
    - Observe 1 hour (Short-Term Emergency Load Limit) of 896 megavolt-amperes (MVA)[18] (160% of the 560 MVA transformer nameplate rating). Following this, 24-hour rating (Long-Term Emergency Loading Limit) rating of 672 MVA (120%).
    - Credits the available system tie-line capacity that can be used to reduce EENS.
- <u>Period of Flexibility Deficit (PFD)</u>
  - Maximum number of hours when the available flexibility capacity offered by system tie-lines was less than the required, resulting in LAR.
  - Calculated for N-0 and N-1 contingencies.

Note that these metrics represent future projections of system performance, and the results of each system configuration should be reviewed relative to the other.

5.0 Results

The attached Quanta Technology report demonstrates that the ASP provides substantial benefit relative to the current Valley South System configuration. The study compares the performance of the Valley South System in its current configuration to the performance of the system after implementing the ASP using forward-looking, quantitative, and customer-benefit driven metrics.

[18] For simplicity, within this document it is assumed that MW = MVA.

Table 1 shows the results for each of the metrics described above for the years 2028 and 2048[19] with and without the ASP and demonstrates the positive impact the ASP has on service reliability performance.

Table 1. Service Reliability Performance of the Valley South System with and without the ASP, 2028 and 2048

Metric	Unit	2028		2048	
		Without ASP	With ASP	Without ASP	With ASP
LAR N-0	MWh	250	0	6,310	3[20]
LAR N-1	MWh	67	0	2,823	202
Flex-1	MWh	163,415	~~49,088~~30,438	526,314	136,664
Flex-2-1	MWh	3,485,449	39,532	4,060,195	87,217
Flex-2-2	MWh	72,331	0	155,780	~~2,161~~100
IP N-0	MW	65	0	288	2
IP N-1	MW	11	0	68	24
PFD N-0	Hours	7	0	77	2
PFD N-1	Hours	32	0	153	14

While the ASP results in substantial improvement in all metrics, the most significant from the perspective of customer impact are the metrics that directly address potential dropped load due to capacity, reliability, and resiliency concerns (i.e., LAR N-0, LAR N-1, Flex-1, Flex-2-1 and Flex-2-2 calculated in units of potential lost MW-hours of service). Table 2 provides comparative results of the cumulative dropped load from the LAR N-0, LAR N-1, Flex-1, Flex-2-1 and Flex-2-2 metrics from 2022[21] through the years 2028 and 2048.

Table 2 – Total Cumulative Load at Risk of Being Dropped with and without the ASP, 2028 and 2048

Metric Category	Metric	2022 – 2028			2022 - 2048		
		Without ASP (MWh)	With ASP (MWh)	*% Reduction*	Without ASP (MWh)	With ASP (MWh)	*% Reduction*
Capacity	LAR N-0	971	0	*100.0%*	56,581	6	*99.9%*
	LAR N-1	274	0	*100.0%*	21,373	~~1,035~~1,047	*95.~~2~~1%*
Reliability & Resiliency	Flex-1	762,859	~~251,663~~103,783	*~~67~~86.4~~.0~~%*	7,841,596	~~2,152,978~~1,817,470	*~~72.5~~76.8%*
	Flex-2-1	23,907,934	245,766	*99.0%*	100,091,707	1,545,650	*98.5%*
	Flex-2-2	450,142	0	*100.0%*	2,788,436	~~8,832~~432	*99.~~7~~9%*

Through 2048, the ASP effectively eliminates the capacity (99.9% reduction in LAR N-0) concerns and substantially addresses the reliability concerns associated with line failures (~~72.5~~76.8% reduction in Flex-1), and substantially mitigates the resiliency concerns associated with loss of transformers serving the Valley South System (98.5% and 99.~~7~~9% reductions in Flex-2-1 and Flex-2-2, respectively).

Other key highlights of the projected service reliability performance for the area served by the

[19] These dates represent the end of the 10 year and 30 year horizon starting in 2018, respectively, which are consistent with the load forecast addressed in other data responses. See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A and DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item G.

[20] The 3 MWh of LAR N-0 in 2048 is caused by an overload on the Alberhill-Fogarty 115 kV Line (the line is first overloaded in 2046), which is correctable by reconductoring. At no time through 2048 are the ASP transformers overloaded under N-0 conditions.

[21] These metrics begin to accrue coincident with the project need year of 2022, and continue to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

current Valley South System with ASP in service are as follows:

- The ASP eliminates transformer capacity shortfalls under N-0 conditions on the Valley South System transformers over the entire 30-year study horizon.
- The ASP eliminates subtransmission line capacity shortfalls under N-0 conditions until 2046, when the Alberhill-Fogarty 115 kV Line is forecasted to become overloaded.
- The ASP eliminates subtransmission line capacity shortfalls under N-1 conditions until 2038, when the Alberhill-Fogarty 115 kV Line is forecasted to become overloaded. Additional 115 kV lines are overloaded under N-1 conditions in 2043 (Alberhill-Skylark) and 2048 (Auld-Moraga #1). As such, requirements for system planning consistent with SCE's Subtransmission Planning Criteria and Guidelines are met until 2038. These shortfalls could be corrected by reconductoring each of the three lines to restore the subtransmission line loading to within capacity limits.
- The ASP creates system tie-line capacity which significantly improves the reliability and resiliency performance during N-1 and N-2 conditions in the area served by the current Valley South System. As demonstrated by the Flex-1 and Flex-2 metrics, the ASP provides the ability to transfer load between the Valley South System and the Alberhill System during these contingency conditions.

Important notes regarding the projected service reliability performance for the current Valley South System *without* any project in service include:

- The Valley South System transformers are projected to overload by year 2022.
- By 2028, over 250 MWh of LAR are observable in the system under N-0 conditions. This extends to 6,310 MWh by 2048 with no project in service.
- Between 2028 and 2048, the flexibility deficit duration in the system increases from 7 hours to 77 hours under N-0 conditions.

A Appendix: Quanta ~~Load Forecast~~Reliability Analysis

The Quanta Technology *Reliability Analysis of Alberhill System Project, Version 2.1 (Second Amended Motion)* is attached as Appendix A to this data submittal.

QUANTA TECHNOLOGY

Report

Reliability Analysis of Alberhill System Project

PREPARED FOR

Southern California Edison (SCE)

DATE

~~January 27~~June 15, 2021
~~(~~Version 2.1 (Errata)

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- Rahul Anilkumar
- Ali Daneshpooy
- Hisham Othman

VERSION HISTORY:

Version	Date	Description
0.1	11/8/2019	Initial draft
0.2	12/5/2019	Final draft
1	12/20/2019	Final
2	1/27/2021	This revision corrects errors identified in the cost-benefit analysis results. Specifically: • Modifying the treatment of reliability benefits into Load at Risk (LAR) without probability weighting. This includes N-1, Flex -1 and Flex – 2 benefit categories. • Treatment of N-1 and N-2 probabilities associated with events in the Valley South System. • Modifying the definition of Flex-2-1 and Flex-2-2 events to no longer constrain the events that drives the impact to occur at peak summer load conditions. The events now account for varying conditions throughout the years. • Removing consideration for SAIDI, SAIFI and CAIDI from the reliability metrics, which were previously provided for information purposes only.
2.1 (Errata)	6/15/2021	This revision corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the reports are unaffected.

EXECUTIVE SUMMARY

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this report is to quantitatively assess the reliability benefits of the ASP.

A comprehensive framework was developed in coordination with SCE to evaluate the performance of the ASP. This evaluation is complemented by the development of load forecasts for the Valley North and Valley South system planning areas. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048).

The benefits were calculated using power-flow studies that evaluate the impact of the load forecast on the Valley South system both without and with the ASP in service. Each of the reliability, capacity, flexibility, and resiliency objectives of the project performance is quantified by service reliability metrics over a 10-year and 30-year planning horizon. Benefits are quantified as the relative performance of the ASP to the baseline for each of the metrics.

The key findings of this study are summarized as follows:

- The peak load forecast identifies a transformer capacity need in the Valley South System by the year 2022 as the load exceeds the Valley South 500/115 kV transformer capacity of 1,120 MVA. The peak demand within the Valley South System is projected to grow from 1,132 MVA in the year 2022 to 1,378 MVA in the year 2048.
- An evaluation of the quantitative metrics demonstrates the benefits of the ASP project in meeting the overall needs in the Valley South System. Key highlights from the ASP project performance across the 10-year (2028) and 30-year (2048) horizons are as follows:
  - Without the ASP in service and under normal operating conditions (N-0 or all facilities in service), the load at risk increases from 250 MWh to 6,300 MWh between the years 2028 and 2048. With the ASP in service, the amount of load at risk is reduced to 3 MWh in 2048.
  - The periods wherein the system observes a shortage in capacity increases from 7 hours by the year 2028 to 77 hours by the year 2048 under normal operating conditions (N-0). With the ASP in service, this is reduced to 2 hours in the year 2048.
  - Without the ASP in service, maintaining adequate N-1 capacity becomes increasingly challenging at higher load levels. The ASP reduces the N-1 capacity risk from 2,800 MWh to 200 MWh by the year 2048.
  - For emergency, unplanned, or planned maintenance events involving the simultaneous outage of two or more sub-transmission circuits in the Valley South system, the availability of tie-lines with the ASP reduces the expected energy unserved by greater than 70%.
  - The ASP provides measurable operational flexibility improvement to address system needs under high impact low probability (HILP) events in the Valley System. The current system configuration does not provide any benefit in this regard due to unavailable system ties.

- The ASP reduces the losses in the system from 52 GWh to 42 GWh in the year 2028 and from 61 GWh to 49 GWh in the year 2048.

Overall, the ASP demonstrated the robustness necessary to address the needs identified in the Valley service territory. By design, the project provides an alternative source of supply into the original Valley South service territory while effectively separating the system with tie-lines. This offers several advantages that can also help overcome the variability and uncertainty associated with the forecast peak load. The available flexibility through system tie-lines provides relief to system operations under both normal system conditions (increasing flexibility for planned maintenance outages) and for abnormal system conditions (unplanned outages) such as N-1, N-2, and HILP events that affect the region.

The findings and results reported in this document are based on publicly available information and the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

TABLE OF CONTENTS

List of Figures

List of Tables

1 INTRODUCTION

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses of the capacity and reliability needs in the Valley South 500/115 kV system. The objective of this analysis is to evaluate the forecasted impacts of the ASP on service reliability performance utilizing a combination of power flow simulations and service reliability metrics where applicable.

In this section of the report, the project background, scope of work, study objective (including task breakdown), and study process have been outlined.

1.1 Project Background

Valley Substation is a 500/115 kV substation that serves electric demand in southwestern Riverside County. Valley Substation is split into two distinct 500/115 kV electrical systems: Valley North and Valley South. Each is served by two 500/115 kV, 560 MVA, three-phase transformers. The Valley South system is not supplied by any alternative means or tie-line. In other words, this portion of the system is radially served by a single point of interconnection from the bulk electric system (BES) which is under the jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility, and resiliency needs of the Valley South system.

The Valley South 115 kV system electrical needs area (ENA) consists of 15 distribution level 115/12 kV substations.

During the most recent forecast developed for peak demand, SCE identified an overload of the Valley South 500/115 kV transformer capacity by the year 2022 under normal operating conditions (N-0). This forecast was developed for extreme weather conditions (1-in-5-year heat storm).[1] SCE has additionally identified the need to provide system ties to improve reliability, resiliency, and operational flexibility.[2] To address these needs, the ASP was proposed. Figure 1-1 provides an overview of the project area. Key features of this project are as follows:

- Construction of a 1,120 MVA 500/115 kV substation (Alberhill Substation).
- Construction of two 500 kV transmission line segments to connect the proposed Alberhill Substation by looping into the existing Serrano–Valley 500 kV transmission line.

[1] 1-in-5-year peak demand adjusted for extreme weather conditions are typically utilized for system planning involving the sub-transmission system.

[2] Flexibility or Operational Flexibility are used interchangeably in the context of this study. It is considered as the capability of the power system to absorb disturbances to maintain a secure operating state. It is used to bridge the gap between reliability and resiliency needs in the system and overall planning objectives. Typically, system tie-lines allow for the operational flexibility to maintain service during unplanned equipment outages, during planned maintenance and construction activities, and to pre-emptively transfer load to avoid loss of service to affected. customers. System tie-lines can effectively supplement transformation capacity by allowing the transfer of load to adjacent systems.

- Construction of approximately 20 miles of 115 kV sub-transmission lines to modify the configuration of the existing Valley South System to allow for the transfer of five 115/12 kV distribution substations from the Valley South System to the new Alberhill System and to create 115 kV system tie-lines between the two systems.

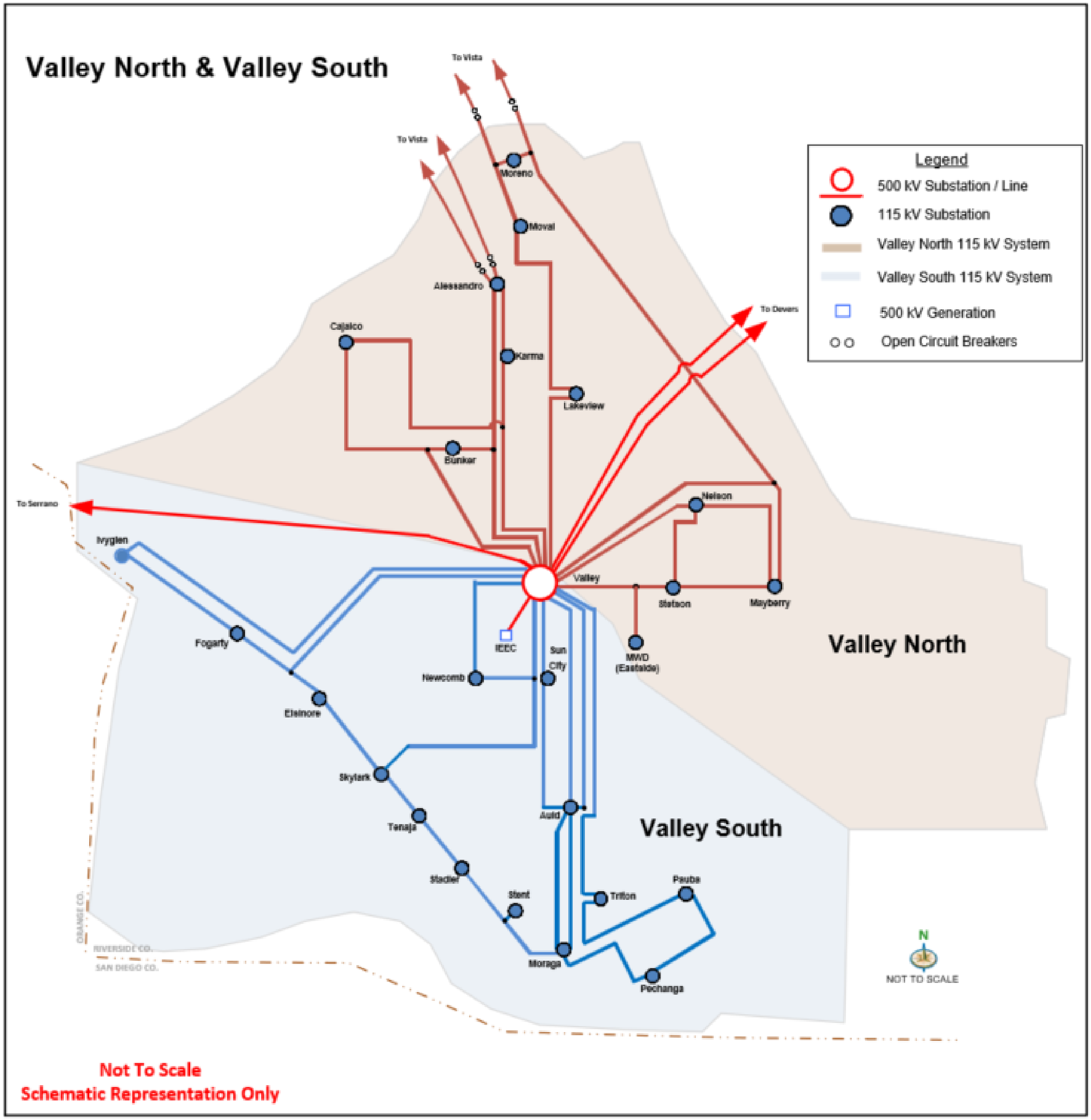

Figure 1-1. Valley Service Areas[3]

[3] Valley-Ivyglen and VSSP 115 kV line projects included.

SCE subsequently submitted an application to the CPUC seeking a Certificate of Public Convenience and Necessity (CPCN). During the proceedings for the ASP, the CPUC requested additional analyses to justify the peak demand forecasts and reliability cases for the project. The CPUC also requested a comparison of the proposed ASP to other potential system alternatives that may satisfy the stated project needs; the alternatives include but are not limited to energy storage, demand response, and distributed energy resources (DERs).

Quanta Technology supported SCE's intent to supplement the existing record in the CPUC proceeding for the ASP utilizing a comprehensive reliability assessment framework. The scope of this assessment included the following:

1. Quantifying the needs in the Valley South 500/115 kV System using the applicable load forecast.
2. Using power flow simulations and quantitative review of project data to evaluate the forecasted impact of proposed ASP on the Valley South System needs.
3. Applying the load forecast to analyze service reliability performance benefits provided by the ASP in the Valley South System.

1.2 Report Organization

In order to provide a comprehensive view of the study methodology, findings, and conclusions, this report has been separated into three sections.

Section 2 of this report introduces the reliability assessment framework while describing the tools, formulation, and overall methodology. The proposed performance metrics are introduced, and their applicability has been described. Section 2.4 presents the forecasted performance of the ASP using the metrics. Section 3 serves as the conclusion.

2 RELIABILITY ASSESSMENT FRAMEWORK AND RESULTS

2.1 Introduction

The objective of this analysis is to evaluate the performance and benefits of the ASP in comparison to the baseline scenario (i.e., no project in service). The performance of the baseline system is initially presented, followed by the ASP. Within the framework of this analysis, reliability, capacity, operational flexibility, and resiliency benefits have been quantified.

In order to successfully evaluate the benefits of a potential project in the Valley South System, its performance must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance,
2. To compare project performance to the baseline scenario (no project in service),
3. To establish a basis to value the performance of the ASP against overall project objectives,
4. To take into consideration the benefits or impacts of flexibility and resiliency (high-impact, low-probability events), and
5. To guide comparison of the projects against the alternatives.

Within the scope of the developed metrics, the following key project objectives are addressed:

Capacity

- Serve current and long-term projected electrical demand requirements in the SCE ENA.
- Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through not only the 10-year planning horizon but also that of a longer-term horizon that identifies needs beyond 10 years, which would allow for an appropriate comparison of alternatives that have different useful lifespan horizons.

Reliability

- Provide safe and reliable electrical service consistent with SCE's Subtransmission Planning Criteria and Guidelines.
- Increase electrical system reliability by constructing a project in a location suitable to serve the ENA (i.e., the area served by the existing Valley South system).

Operational Flexibility and Resiliency

- Increase system operational flexibility and maintain system reliability (e.g., by creating system ties that establish the ability to transfer substations from the current Valley South system and to address both normal condition capacity and N-1 capacity needs).

2.2 Study Methodology

In order to develop a framework to effectively evaluate the performance of a project, the overall study methodology was broken down into the following elements:

1. Develop metrics to establish project performance.
2. Quantify the project performance using commercial power flow software.

Each of the above areas is further detailed throughout this chapter. Since the focus of this analysis is the Valley South system, all discussions are pertinent to this study area.

2.2.1 Study Inputs

SCE provided Quanta Technology with information pertinent to the Valley South, Valley North, and ASP systems. This information encompassed the following data:

1. GE PSLF[4] power flow models for Valley South and Valley North Systems.
    a. 2018 system configuration (current system).
    b. 2021 system configuration (Valley-Ivyglen[5] and VSSP[6] projects modeled and included).
    c. 2022 system configuration (with the ASP in service).
2. Substation layout diagrams representing the Valley Substation.
3. Impedance drawings for the Valley South and Valley North Systems depicting the line ratings and configurations.
4. Single-line diagram of the Valley South and Valley North Systems.
5. Contingency processor tools to develop relevant study contingencies to be considered for each system configuration
6. 8,760 load shape of the Valley South System.
7. Metered customer information per substation (customer count).

The reliability assessment utilizes the spatial load forecast developed for Valley South and Valley North service territories to evaluate the performance of the system for future planning horizons. The developed forecast includes the effects of future developments on photovoltaic projects or installations, electric vehicles, energy efficiency, energy storage, and load modifying demand response as defined in the IEPR 2018 forecast.[7] The representative load forecast is presented in Figure 2-1, which demonstrates system deficiency in the year 2022, where the loading on the Valley South system transformers exceeds maximum operating limits (1,120 MVA).

[4] General Electric's Positive Sequence Load Flow (PSLF) program.

[5] Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018).

[6] VSSP (Valley South 115 kV Sub-transmission Project) CPUC Decision 16-12-001 (issued December 1, 2016).

[7] California Energy Commission, "2018 Integrated Energy Policy Report," 2018.

Benefits begin to accrue coincident with the project need year of 2022. For this assessment, it is assumed that the ASP will be in service by this year and that benefits accrue from 2022 to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

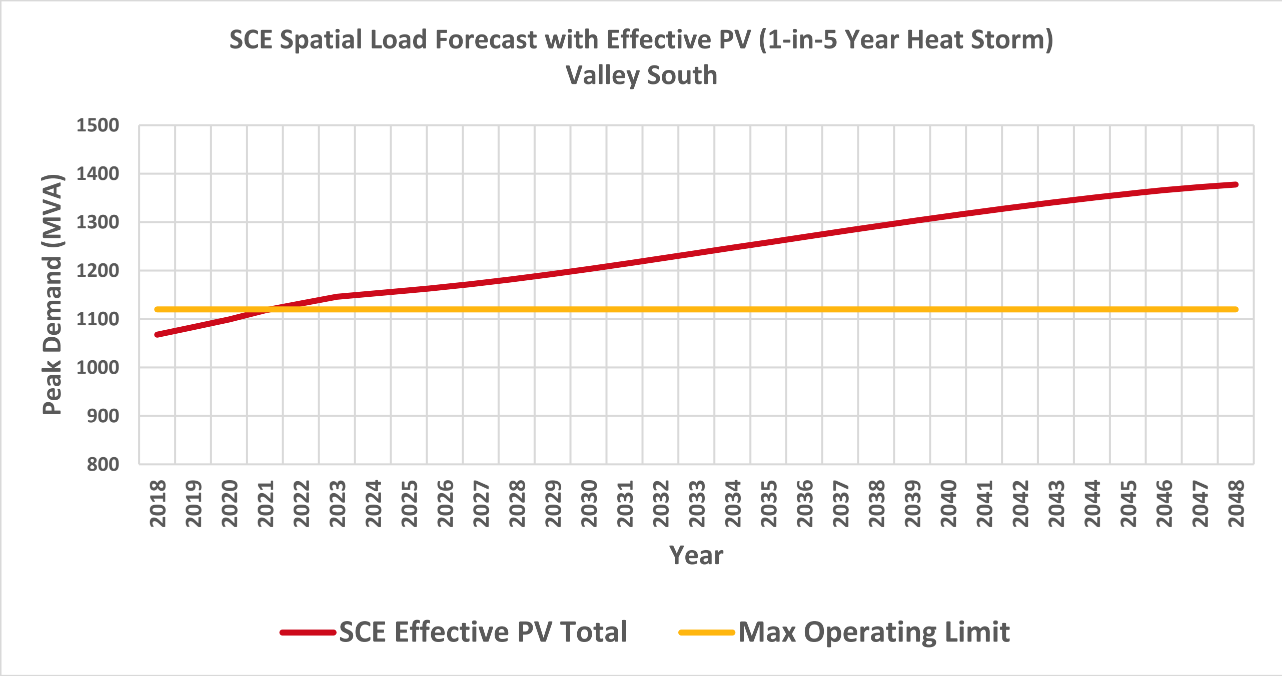

Figure 2-1. Valley South Load Forecast (Peak MVA)

System configuration for the years 2018, 2021, and 2022 are depicted in Figure 2-2 through Figure 2-4.

The load shape of the year 2016 was selected for this study. This selection was made because it demonstrates the largest variability among available records.[8] This load shape is presented in Figure 2-5.

[8] Note that the load shapes of years 2017 and 2018 were skewed due to the use of the AA-bank spare transformers as overload mitigation. Therefore, the load shape for year 2016 was adopted. Its shape is representative only and does not change among years.

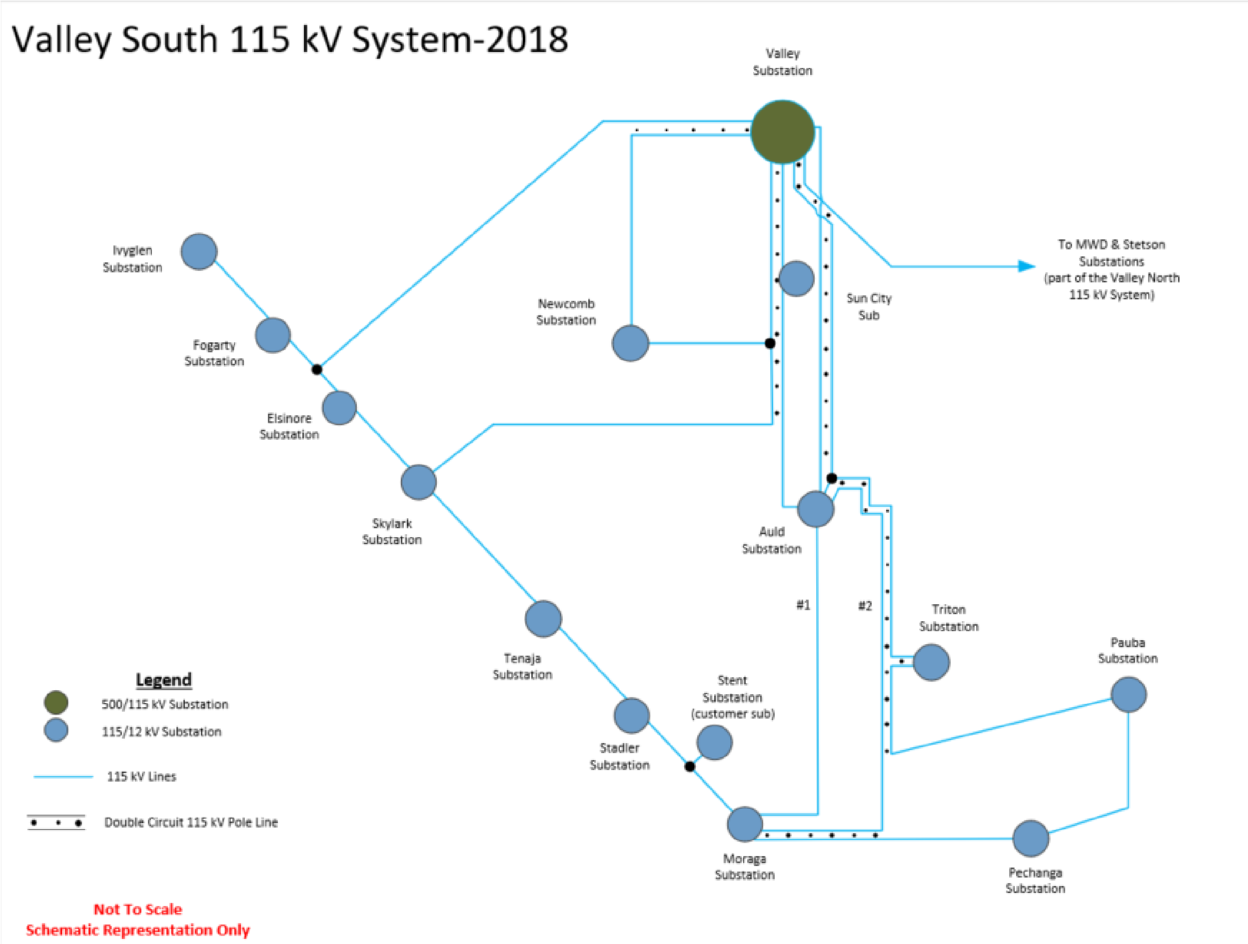

Figure 2-2. Valley South System Configuration (2018)

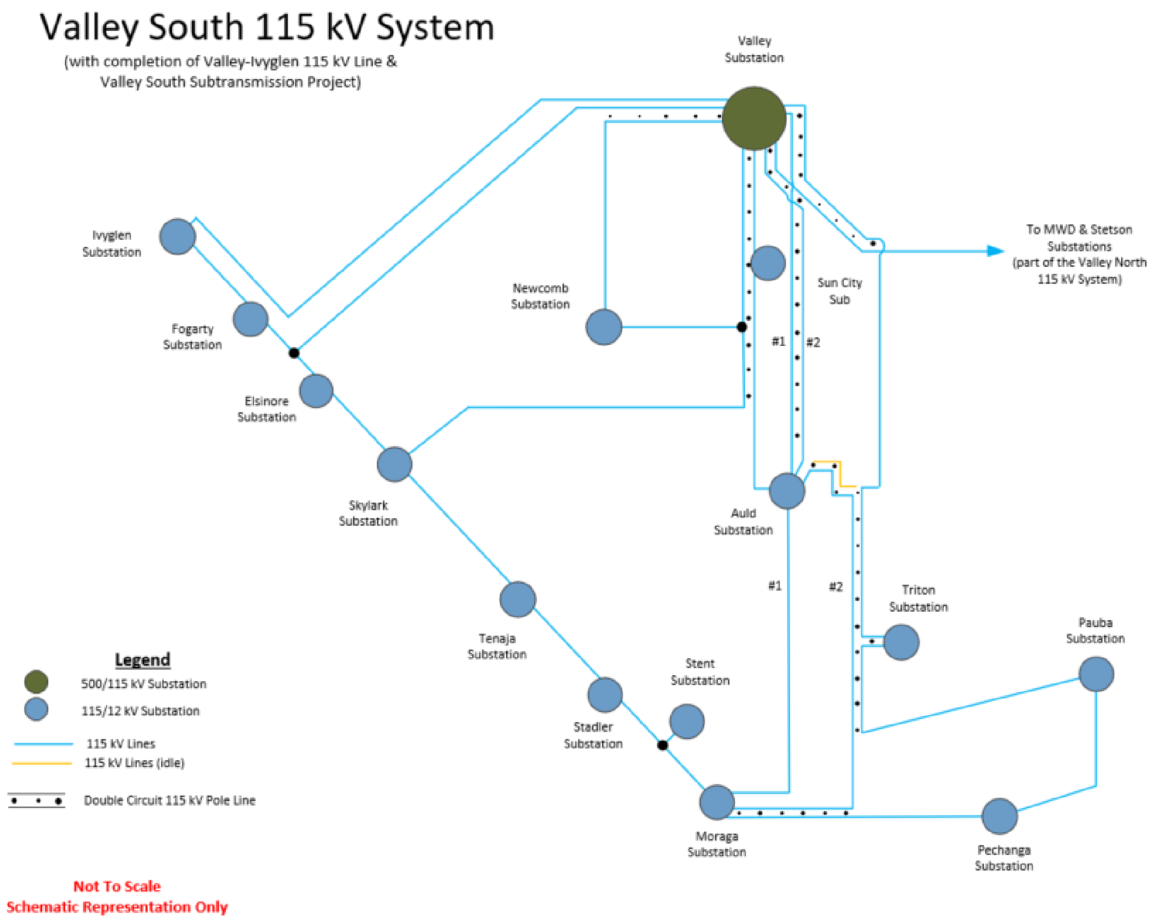

Figure 2-3. Valley South System Configuration (2021)

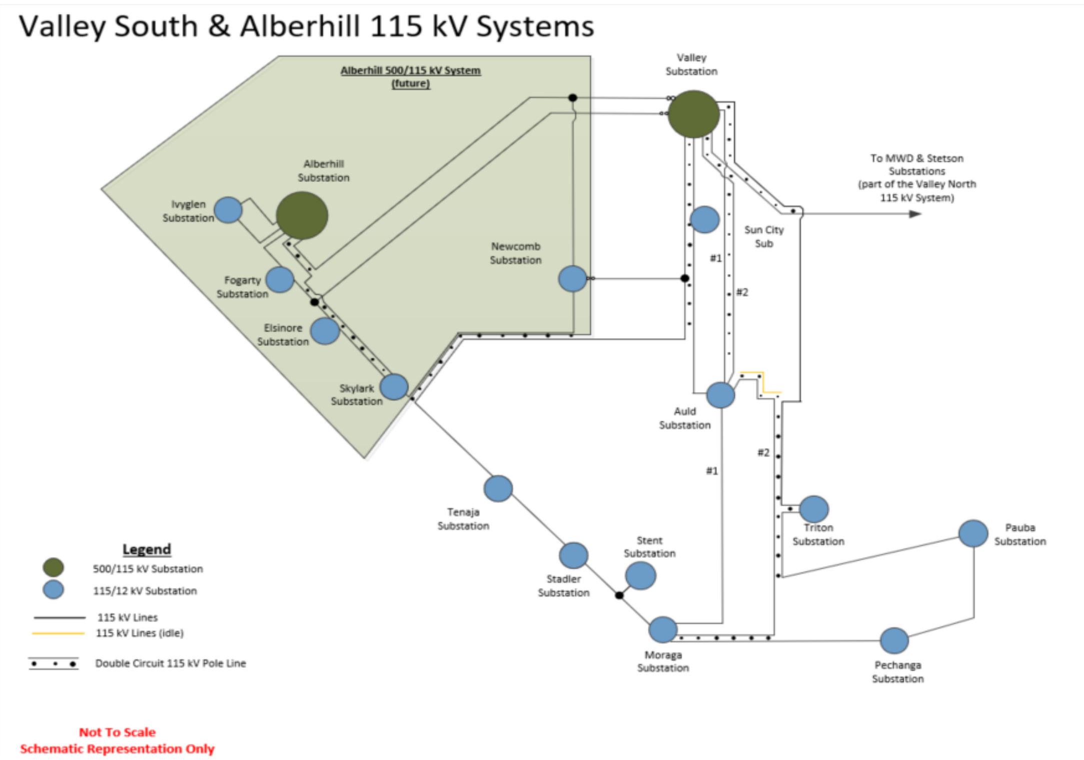

Figure 2-4. Valley South System Configuration (2022 with the ASP in service)

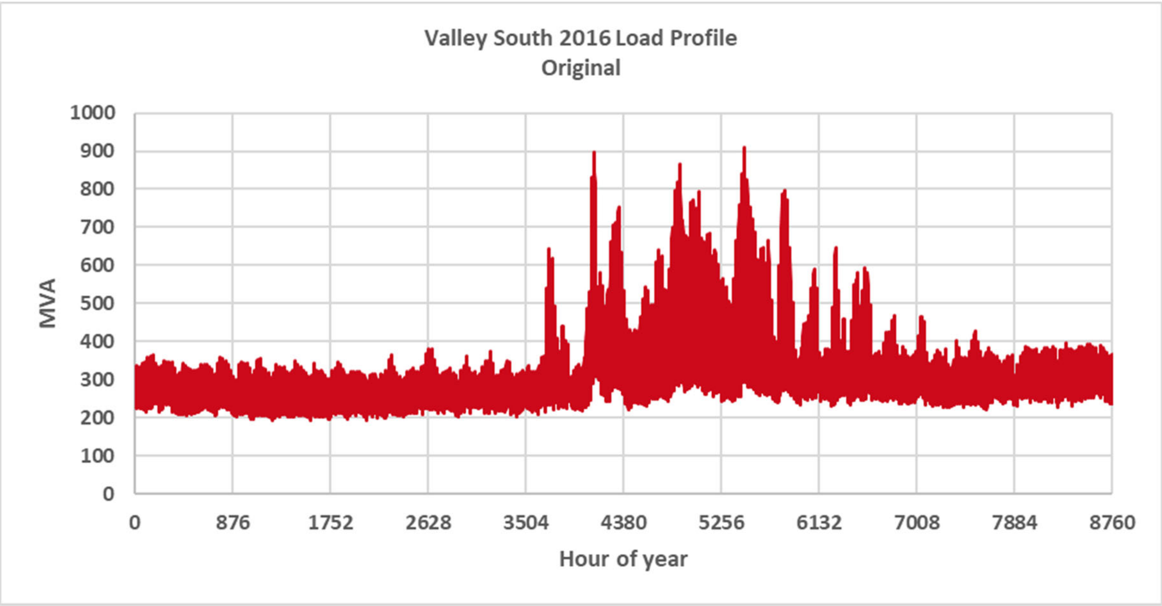

Figure 2-5. Load Shape of the Valley South Substation

2.2.2 Study Criteria

The following guidelines have been used through the course of this analysis to ensure consistency with SCE planning practices:

- The study and planning of projects adhered to SCE's Subtransmission Planning Criteria and Guidelines. Where applicable, North American Electric Reliability (NERC) and Western Electricity Coordinating Council (WECC) standards have been used, especially while taking into consideration the impact on the BES and the non-radial parts of the system under CAISO control.
- Transformer overload criteria established per SCE Subtransmission Planning Criteria and Guidelines for AA banks have been utilized.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 (normal) and N-1 (emergency) operating conditions.
- Voltage limits of 0.95–1.05 per unit (pu) under N-0 and N-1 operating configurations.
- Voltage deviation within established limits of ±5% post contingency.

2.2.3 Reliability Study Tools and Application

A combination of power flow simulation tools has been used for this analysis (i.e., GE PSLF and PowerGem TARA). GE PSLF has been used for base-case model development, conditioning, contingency development, and drawing capabilities. TARA has been used to perform time-series power-flow analysis.

Time-series power-flow analysis is traditionally used in distribution system analysis to assess variation of various quantities over time with changes in load, generation, transmission-line status, etc. It is now finding common application even in transmission system analysis, especially when the system under study is not heavily meshed (radial in nature).

In this analysis, the peak load MVA of the load shape has been adjusted (scaled) to reflect the peak demand for each future year under study. This is represented by Figure 2-6 for the Valley South System as an example. The MW peak load is then distributed amongst the various load models in the Valley Substation in proportion to their MW-to-peak-load ratio in the base case. Load centers under consideration in this analysis of the Valley South and Valley North Systems are listed in Table 2-1.

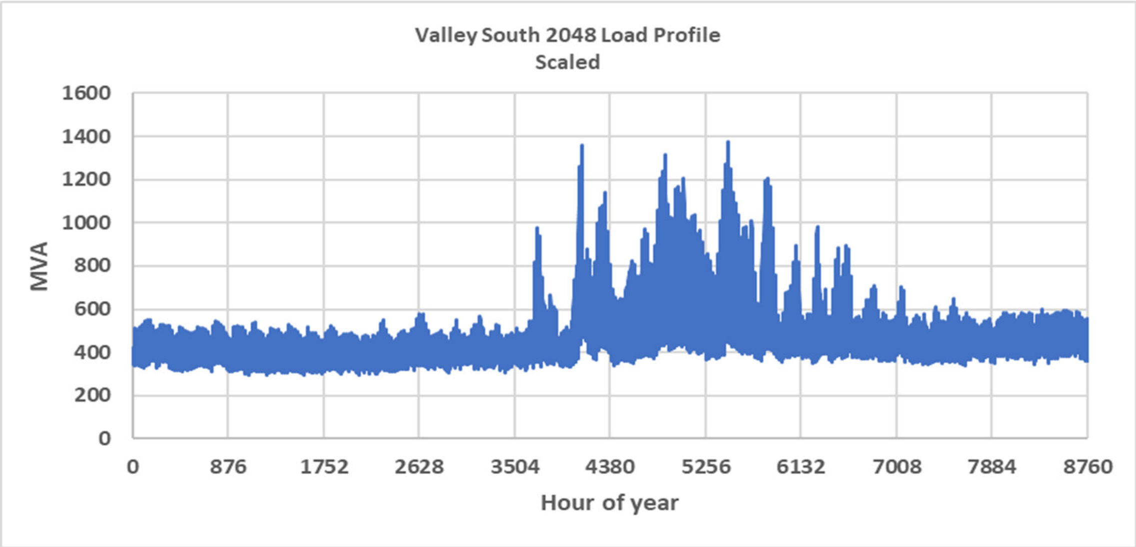

Figure 2-6. Scaled Valley South Load Shape Representative of Study Years

Table 2-1. Distribution Substation Load Buses

Valley South	Valley North
Auld	Alessandro
Elsinore	Bunker
Fogarty	Cajalco
Ivyglen	ESRP_MWD
Moraga	Karma
Newcomb	Lakeview
Pechanga	Mayberry
Pauba	Moreno
Skylark	Moval
Stadler	Nelson
Stent	Stetson
Sun City	
Tenaja	
Triton	

The hourly study (i.e., 8,760 simulations per year) was conducted in selected years (5-year periods from 2022 including 2027, 2032, 2037, 2042, and 2048). The results for years in between were interpolated.

For each simulation, the AC power-flow solution is solved, relevant equipment is monitored under N-0 conditions (normal) and N-1 analysis (emergency), potential reliability violations are recorded, and performance reliability metrics (as described in Section 2.2.4) are calculated. A flowchart of the overall study process is presented in Figure 2-7.

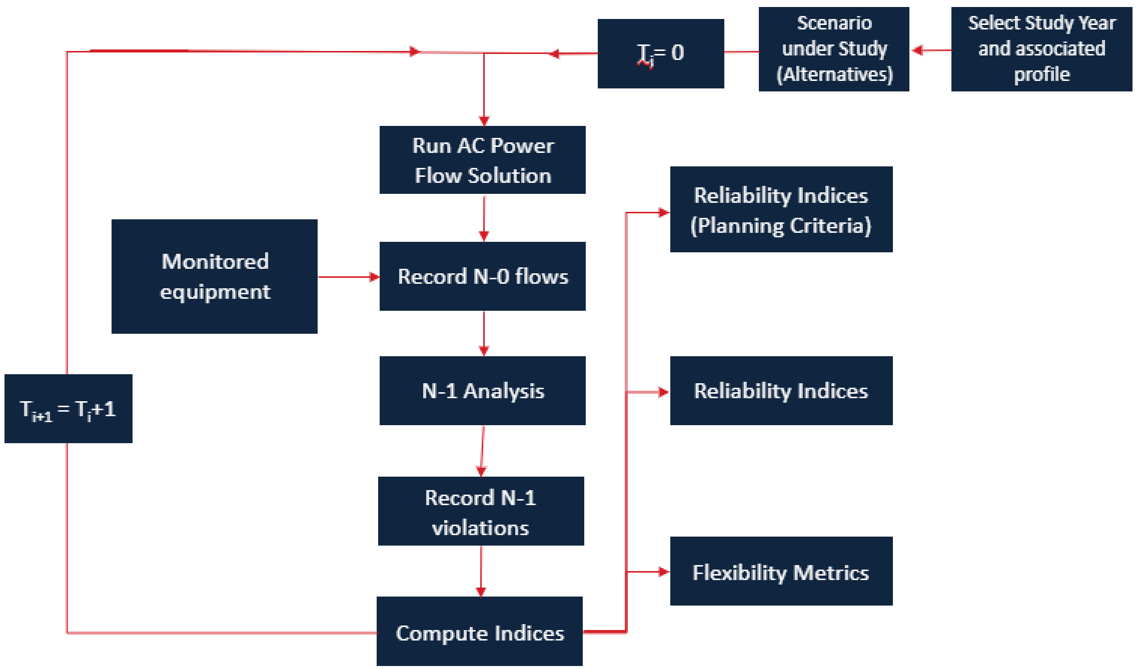

Figure 2-7. Flowchart of Reliability Assessment Process

Unless otherwise specified, all calculations performed under the reliability analysis compute the load at risk, which is not a probability-weighted metric.

In the reliability analysis, the N-1 contingency has been evaluated for every hour of the 8,760 simulations, and all outages are considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates single circuit outages for all sub-transmission lines within the system. Whenever an overload or voltage violation was observed, the binding constraint was applied to the computation of the relevant reliability metric. When the project under evaluation has system tie-lines that can be leveraged, they are engaged to minimize system impacts.

Several flexibility metrics were developed to evaluate the incremental benefits of system tie-lines under emergency or planned/unplanned outages and high-impact, low-probability (HILP) events in the Valley South System.

The Flexibility-1 metric evaluates the system under N-2 (double line outage) conditions, which is representative of combinations of lines switched out for service. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates double-circuit outages for all sub-transmission lines that share a common structure. The objective of this metric is to gauge the incremental benefits that projects provide for events that would traditionally result in unserved energy in the Valley South System. The flow chart in Figure 2-8 presents the overall process. The analysis is initiated taking into consideration the peak loading day (24-hour duration) and applying the N-2 contingencies at each hour. Whenever an overload or voltage violation was observed, the binding constraint is used to determine the MWh load at risk. The results were compared against the baseline system and utilized as the common denominator to scale other days of the year for aggregation into the flexibility metric. When the project under evaluation has tie-lines, they are considered to minimize system impacts.

The Flexibility-2 metric evaluates the project performance under HILP events in the Valley South System. This has been broken down into two components that consider different events impacting the Valley South ENA. Both components utilize a combination of power flow and load profile analysis to determine the amount of load at risk:

- The Flexibility 2-1 metric evaluates the impact of the entire Valley Substation out of service, wherein all the load served by Valley Substation is at risk. Considering a 2-week event (assumed substation outage duration to fully recover from an event of this magnitude), the average amount of load at risk is determined. Utilizing power flow simulations to evaluate the maximum load that can be transferred by projects using system ties, the amount of load that can be recovered is estimated.
- The Flexibility 2-2 metric evaluates a condition wherein Valley South System is served by a single transformer (i.e., two load-serving transformers at Valley Substation are out of service). This scenario is a result of a catastrophic failure (e.g., fire or explosion) of one of the two normally load-serving transformers, and causing collateral damage to the adjacent transformer, rendering both transformers unavailable. Under these conditions, the spare transformer is used to serve a portion of the load. Using the 8,760-load shape and the transformer short-term/long-term emergency loading limits (STELL/LTELL), the average amount of MWh load at risk is estimated and aggregated considering a 2-week duration (mean time to repair under major failures). The analysis accounts for the incremental relief offered by solutions with permanent and temporary load transfer using system ties.

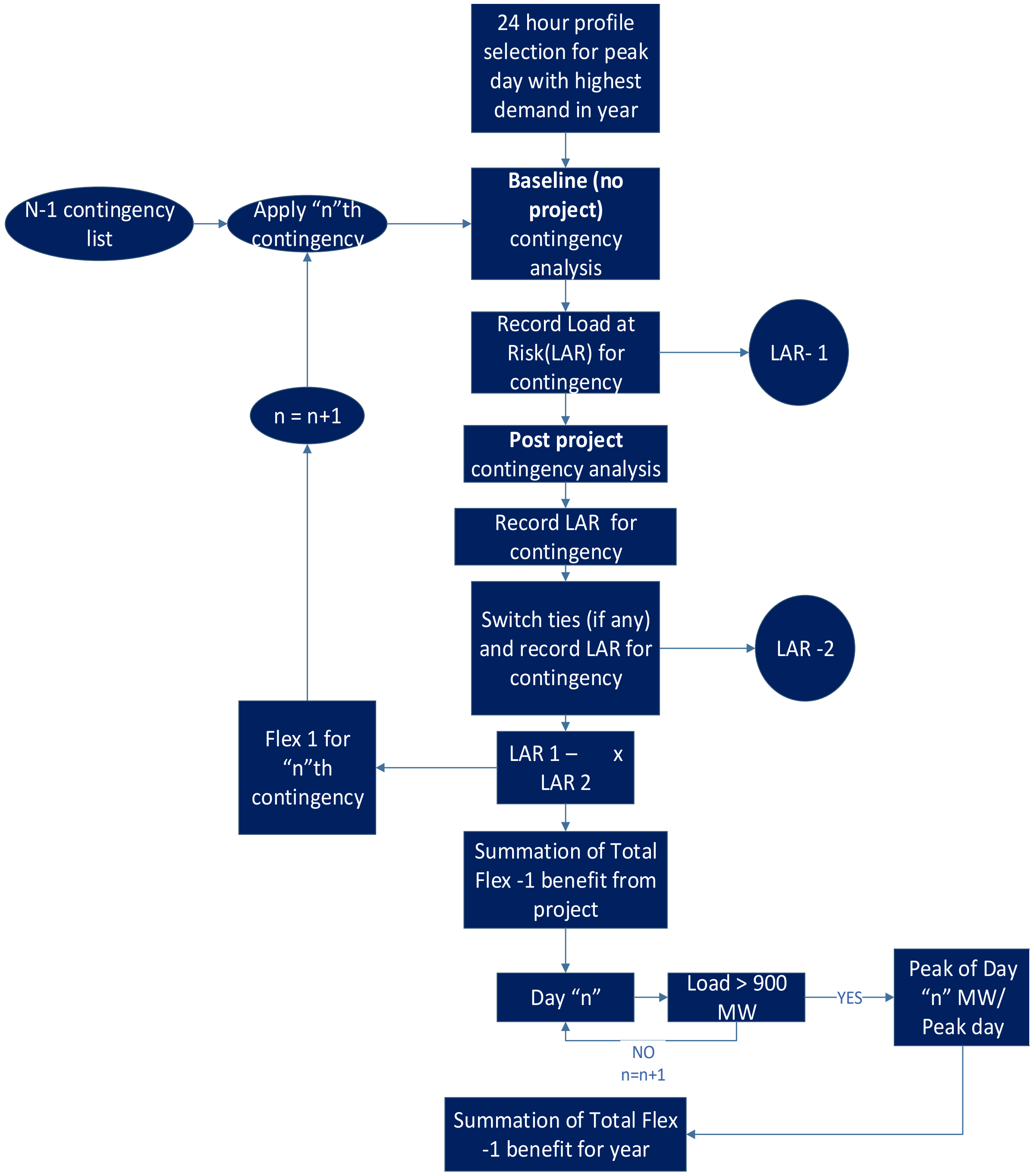

Figure 2-8. Flowchart of Flexibility Metric 1 (Flex 1) Calculation Process

2.2.4 Reliability Metrics

Before introducing reliability metrics, the key elements of the overall project objectives must be outlined to provide direction and to guide further analysis. The treatment of the following is consistent with applicable NERC guidelines and standards for the BES:

- Reliability has been measured with reference to equipment rating (thermal overload) and voltage magnitude (low voltages).
- Capacity represents the need to have adequate resources to ensure that the electricity demand can be met without service outages. Capacity is evaluated under normal and emergency system conditions, and normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address an emergency, maintenance, and planned outage conditions. Therefore, it is expected to operate the system radially and accommodate flexibility by employing normally open tie(s) and connection(s).
- Resiliency has been viewed as an extension of the flexibility benefits, wherein ties and connections are leveraged to recover load under HILP events in the system.

Building on the overall project objectives, the reliability metrics described in the following subsections have been established.

2.2.4.1 Quantitative Metrics

The following quantitative metrics have been proposed to address the reliability, capacity, flexibility, and resiliency needs of the system:

- **Load at Risk**
  a. This is quantified by the amount of MWh at risk from each of the following elements:
     i. For each thermal overload, the MW amount to be curtailed to reduce loading below ratings. This includes transformers and lines serving the Valley South system.
     ii. For voltage violations, the MW amount of load to be dropped based on voltage sensitivity of the bus to bring voltage within limits. The sensitivity study established ranges of load shed associated with varying levels of post-contingency voltage. For the deviation of 1 pu of voltage from the 0.95 pu limit, 0.5 MW of load shed was identified.
  b. Computed for N-0 events and N-1 events and aggregated over the course of the year.
  c. For N-1 events, tie-lines are used where applicable to minimize the amount of MWh at risk.

- **Maximum Interrupted Power (IP)**
  a. This is quantified as the maximum amount of load in MW dropped to address thermal overloads and voltage violations. In other words, it is representative of the peak MW overload observed among all overloaded elements.
  b. Computed for N-0 events and N-1 events.

- **Losses**: Losses are treated as the active power losses in the Valley South system. New lines introduced by the scope of a project have also been included in the loss computation.

- **Availability of Flexibility in the System**: The measure of the availability of the flexible resource (tie-lines, switching schemes) to serve customer demand. It provides a proxy basis for the amount of additional/incremental flexibility (MWh) the alternative solution provides to the system for maintenance operations, emergency events, or the need to relieve other operational issues. Two flexibility metrics are considered:
  a. Flexibility 1: Capability to recover load for maintenance and outage conditions.
     i. Calculated as the amount of energy not served for N-2 events. The measure of the capability of the project to provide flexibility to avoid certain overloads and violations observable under the traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served utilizing the flexibility attributes of the project.
     ii. Considering the large combination of N-2-line outages that potentially impact the Valley South System, the analysis is limited to only circuits that share a common double circuit pole.

  b. Flexibility 2: Recover load for the emergency condition: Single point of failure Valley South substation and transformer banks.
     i. Flex 2-1: Calculated as the energy unserved when the system is impacted by low probability high consequence events such as the loss of the entire Valley Substation. Projects that establish ties or connections to an adjacent network can support the recovery of load during these events. This event is calculated over an average 2-week period (average restoration duration for events of this magnitude) in the Valley system.

        Flex 2-2: Calculated as the amount of MWh load at risk when the system is operating with a single (spare) transformer at Valley Substation (both transformers are out of service due to major failures). This event is calculated over an average 2-week period in the Valley System. Projects that establish ties or connections to an adjacent network can support the recovery of load during these events.

- **Period of Flexibility Deficit (PFD)**: The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) was less than required, resulting in energy being unserved for a given time horizon and direction.

The above list has been iteratively developed to successfully translate the objectives into quantifiable metrics that provide a basis for project performance evaluation.

2.3 Reliability Analysis of the Baseline System

The baseline system is the no-project scenario within this analysis. It depicts a condition wherein the load grows to levels established by the forecast under the study without any project in service to address the shortfalls in transformer rated capacity. This scenario forms the primary basis for comparison against the ASP performance to evaluate the benefits associated with the project.

The baseline system has been evaluated under the study years 2022 (project need year), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 2.2.4 has been calculated using the study methodology outlined in Section 2.2.3.

2.3.1 System Performance under Normal Conditions (N-0)

Table 2-2 presents the findings from system analysis under N-0 conditions in the system.

Table 2-2. Baseline N-0 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
No Project	**2022**	22	13	2
	2028	250	65	7
	2033	905	120	18
	2038	2212	190	37
	2043	4184	246	53
	2048	6310	288	77

2.3.2 System Performance under Normal Conditions (N-1)

Table 2-3 presents the findings from system analysis under N-1 conditions.

Table 2-3. Baseline N-1 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
No Project	**2022**	10	2	14
	2028	67	11	32
	2033	249	21	54
	2038	679	35	88
	2043	1596	45	120
	2048	2823	68	153

In the baseline system analysis, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the load at risk among other reliability metrics under study (reported for 2022 and beyond). In Table 2-4, only the thermal violations associated with each constraint are reported.

Table 2-4. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Year of Overload
Valley South Transformer	N-0	Base case	2022
Auld to Moraga #1	N-0	Base case	2047
Auld to Moraga #2	N-1	Auld-Moraga #1	2038
Auld to Moraga #1	N-1	Auld-Moraga #2	2022
Valley EFG to Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043
Tap 39 to Elsinore	N-1	Valley EFG-Newcomb-Skylark	2038
Auld to Moraga #1	N-1	Skylark-Tenaja	2048
Skylark to Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033
Valley EFG to Sun City	N-1	Valley EFG-Auld #1	2043
Valley EFG to Auld #1	N-1	Valley EFG-Sun City	2048
Valley EFG to Tap 22	N-1	Valley EFG-Newcomb	2043
Valley EFG to Auld #1	N-1	Valley EFG-Auld #2	2048
Valley EFG to Sun City	N-1	Valley EFG-Auld #2	2043
Auld to Moraga #1	N-1	Valley EFG - Triton	2043
Moraga-Pechanga	N-1	Valley EFG - Triton	2038

2.3.3 Flexibility Metrics

Table 2-5 presents the findings from system analysis for Flex 1 and Flex 2 metrics. The Flex 2 metric results represent the average load at risk during the 2-week recovery period for the defined scenario.

Table 2-5. Flexibility and Resiliency Metrics for the Baseline System

	Year	Flex 1 Load at Risk (MWh)	Flex 2-1 Average Load at Risk (MWh)	Flex 2-2 Average Load at Risk (MWh)
No Project	**2022**	54,545	127,935	2,138
	2028	163,415	133,688	2,774
	2033	254,140	139,702	3,514
	2038	344,864	145,991	4,421
	2043	435,589	151,619	5,294
	2048	526,314	155,733	5,975

2.3.4 System Losses

Table 2-6 presents the aggregated losses from the 8,760 assessment of the Valley South system.

Table 2-6. Losses in the Baseline System

	Year	Losses (MWh)
No Project	**2022**	49,667
	2028	52,288
	2033	54,472
	2038	56,656
	2043	58,840
	2048	61,024

2.3.5 Key Highlights of System Performance

The key highlights of system performance for the baseline system are as follows:

1. Without any project in service, the Valley South transformers are overload by the year 2022 (above maximum transformer ratings).
2. By the year 2028, 250 MWh of the load is observed to be at risk in the system under N-0 conditions. This extends to 6,309 MWh by 2048 with no project in service.
3. Between 2028 and 2048, the flexibility deficit in the system increases from 7 hours to 77 hours under the N-0 condition.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasingly challenging to maintain the system N-1 secure.

2.4 Reliability Analysis of the Alberhill System Project

The ASP has been evaluated under the study years 2022, 2028, 2033, 2038, 2043, and 2048 consistent with the baseline system. Each of the reliability metrics established in Section 2.2.4 has been calculated using the study methodology outlined in Section 2.2.3.

2.4.1 Description of Project Solution

The ASP would be constructed in Riverside County and includes the following components:

1. Construction of a new 1,120 MVA 500/115 kV substation to increase the electrical service capacity to the area presently served by the Valley South 115 kV system.
2. Construction of two new 500 kV transmission line segments to connect the new substation to SCE's existing Serrano–Valley 500 kV transmission line. The total length is 3.3 miles.
3. Construction of a new 115 kV subtransmission line and modifications to existing 115 kV subtransmission lines to transfer five existing 115/12 kV substations (Ivyglen, Fogarty, Elsinore,

Skylark, and Newcomb) presently served by the Valley South 115 kV system to the new 500/115 kV substation. The total length is approximately 20.4 miles.

4. Installation of telecommunications improvements to connect the new facilities to SCE's telecommunications network. The total length is approximately 8.7 miles.

Figure 2-9 presents an overview of the project layout and schematic.

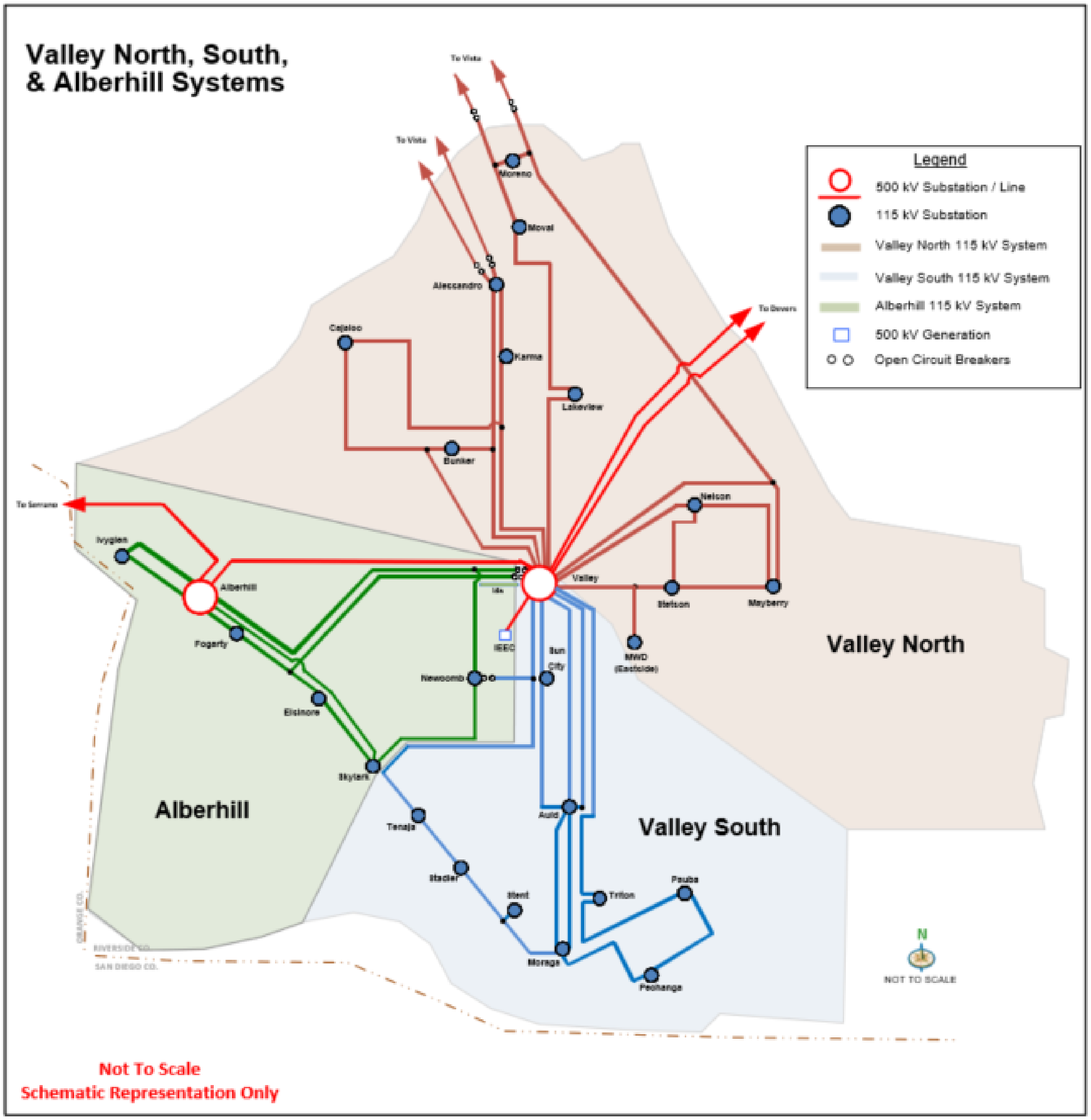

Figure 2-9. Service Territory Configuration after Proposed Alberhill System Project

2.4.2 System Performance under Normal Conditions (N-0)

Table 2-7 presents the findings from system analysis under N-0 conditions.

Table 2-7. Alberhill N-0 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
ASP	**2022**	**0**	**0**	**0**
	2028	0	0	0
	2033	0	0	0
	2038	0	0	0
	2043	0	0	0
	2048	3	2	2

2.4.3 System Performance under Normal Conditions (N-1)

Table 2-8 presents the findings from system analysis under N-1 conditions.

Table 2-8. Alberhill N-1 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
ASP	2022	**0**	**0**	**0**
	2028	0	0	0
	2033	0	0	0
	2038	21	8	4
	2043	84	17	8
	2048	202	24	14

In analyzing the ASP, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the load at risk among other reliability metrics under study (reported for 2022 and beyond).

In Table 2-9 below, only the thermal violations associated with each constraint are reported.

Table 2-9. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Year of Overload
Alberhill to Fogarty	N-0	Base case	2046
Alberhill to Fogarty	N-1	Alberhill–Skylark	2038
Alberhill to Skylark	N-1	Alberhill–Fogarty	2043
Auld to Moraga #1	N-1	Valley EFG–Newcomb–Tenaja	2048

2.4.4 Flexibility Metrics

Table 2-10 present the findings from system analysis for Flex 1 and Flex 2 metrics. The Flex 2 metric results represent the average load at risk during the 2-week recovery period for the defined scenario.

Table 2-10. Flexibility and Resiliency Metrics for the ASP

	Year	Flex 1 Load at Risk (MWh)	Flex 2-1 Average Load at Risk (MWh)	Flex 2-2 Average Load at Risk (MWh)
ASP	2022	~~22,815~~0	1,163	0
	2028	~~49,088~~30,438	1,516	0
	2033	56,720~~70,982~~	1,947	0
	2038	~~92,876~~83,001	2,452	0
	2043	109,282~~114,770~~	2,954	1
	2048	136,664	3,345	4

2.4.5 System Losses

Table 2-11 presents the aggregated losses from the 8760 assessment of the Valley South and ASP systems.

Table 2-11. Losses in the ASP

	Year	Losses (MWh)
ASP	2022	40,621
	2028	42,671
	2033	44,380
	2038	46,089
	2043	47,797
	2048	49,506

2.4.6 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the study horizon. 3 MWh of load at risk is recorded under N-0 condition in the year 2048 due to an observed overload of the Alberhill–Fogarty 115 kV line.
2. By the year 2038, overloads due to N-1 events will be observable on the Alberhill–Fogarty 115 kV circuit, Alberhill–Skylark 115 kV, and Auld–Moraga 115 kV circuits, which cannot be resolved by potential transfer flexibility.
3. The project provides significant flexibility to address N-1 and N-2 events in the system while also providing significant benefits to address needs under HILP events that occur in the Valley System.

2.5 Evaluation of Quantitative Metrics

The established performance metrics were compared between the baseline and the ASP to quantify the overall benefits accrued over the 10-year and 30-year study horizons calculated at the start of the need year 2022 (i.e., end of 2021). The benefits are quantified as the difference between the baseline and the ASP for each of the metrics and discounted at SCE's weighted aggregate cost of capital (WACC) of 10%. As an example, Figure 2-10 exhibits N-0 load at risk values over the study horizon and its present worth using discount rate of WACC. A similar process was applied to other metrics.

The present worth of *benefits* for reliability metrics over 10-year and 30-year horizons are presented in Table 2-13. The cumulative *benefits* over a 10-year and 30-year horizon are presented in Table 2-12.

The cumulative and present worth of benefits are presented in Appendix C: Reliability Performance Additional Details for both the baseline and the ASP to provide a relative comparison of performance in each reliability category.

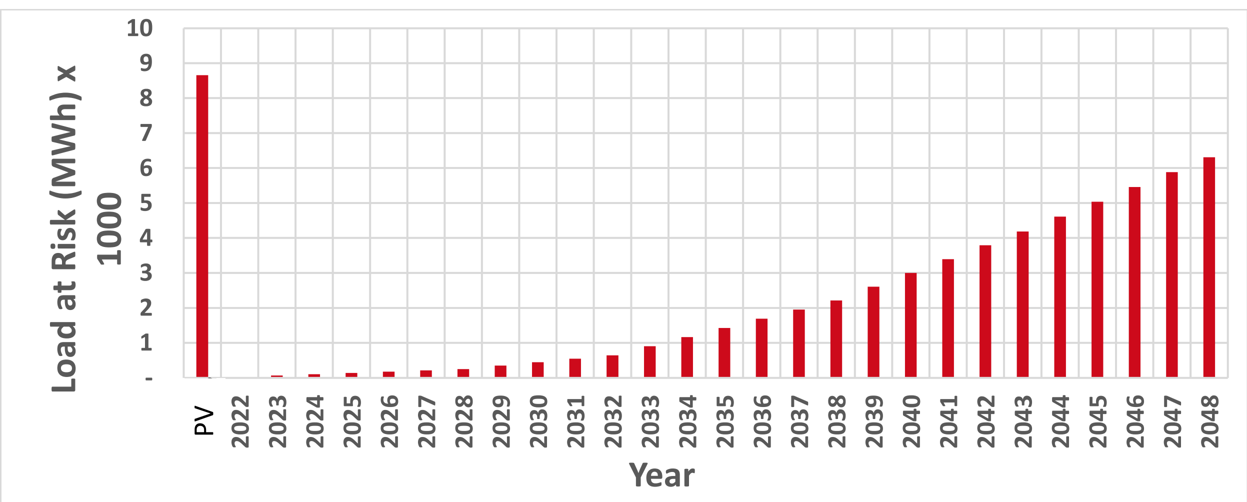

Figure 2-10. N-0 Load at Risk over the Study Horizon and Its PV

Appendix C provides comparative metrics over the 10-year and 30-year horizon between the baseline (no project) and the ASP. These are used to derive the benefits presented in Table 2-12 and (later in Table C-1).

Table 2-12. Cumulative Benefits between Baseline and ASP (10-year and 30-year)

Category	Component	Cumulative Value of Benefits over 10-year horizon (until 2028)	Cumulative Value of Benefits over 30-year horizon (until 2048)
N-0	Losses (MWh)	65,319	277,608
N-1	Load at Risk (MWh)	274	20,~~339~~326
N-1	IP (MW)	45	601
N-1	PFD (hr)	173	1,907
N-1	Flex 1 Load at Risk (MWh)	~~511,196~~659,076	~~5,688,618~~6,024,126
N-1	Flex 2-1 Average Load at Risk (MWh)	907,590	3,779,849
N-1	Flex 2-2 Average Load at Risk (MWh)	17,266	106,937
N-0	Load at Risk (MWh)	971	56,575
N-0	IP (MW)	288	4,053
N-0	PFD (hr)	35	811

Table 2-13. Present Worth of Benefits between Baseline and ASP (10-year and 30-year)

Category	Component	Present Worth of Benefits over 10-year horizon (until 2028)	Present Worth of Benefits over 30-year horizon (until 2048)
N-0	Losses (MWh)	45,254	90,384
N-1	Load at Risk (MWh)	173	2,896
N-1	IP (MW)	28	133
N-1	PFD (hr)	115	420
N-1	Flex 1 Load at Risk (MWh)	434,402~~330,171~~	1,438,932~~1,281,190~~
N-1	Flex 2-1 Average Load at Risk (MWh)	629,646	1,243,232
N-1	Flex 2-2 Average Load at Risk (MWh)	11,822	29,195
N-0	Load at Risk (MWh)	606	8,657
N-0	IP (MW)	185	853
N-0	PFD (hr)	23	146

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the ASP. The results for each category of benefits demonstrate the merits of the ASP to complement the increasing reliability, capacity, flexibility, and resiliency needs in the Valley South service area.

3 CONCLUSIONS

SCE retained Quanta Technology to supplement the existing record in the CPUC proceedings for the ASP with additional analyses to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this report is to quantitatively assess the reliability benefits of the ASP.

A comprehensive framework was developed in coordination with SCE to evaluate the performance of the ASP. This evaluation is complemented by the development of load forecasts for the Valley North and Valley South system planning areas. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048).

The benefits were calculated using power flow studies that evaluate the impact of the load forecast on the Valley South System both without and with the ASP in service. Each of the reliability, capacity, flexibility, and resiliency objectives of project performance is quantified by service reliability metrics over a 10-year and 30-year planning horizon. Benefits are quantified as the relative performance of the ASP to the baseline for each of the metrics.

The key findings of this study are summarized as follows:

- The peak load forecast identifies a transformer capacity need in the Valley South system by the year 2022, as the load exceeds Valley South 500/115 kV transformer capacity of 1,120 MVA. The peak demand within Valley South service territory is projected to grow from 1,132 MVA in the year 2022 to 1,378 MVA in the year 2048.
- An evaluation of the quantitative metrics demonstrates significant benefits of the ASP project in meeting overall needs in the Valley South service area. Key highlights from the ASP project performance across the 10-year (2028) and 30-year (2048) horizons are discussed.
  - Without the ASP in service and under normal operating conditions (N-0 or all facilities in service), the load at risk increases from 250 MWh to 6,300 MWh between the years 2028 and 2048. With the ASP in service, the amount of load at risk is reduced to 3 MWh in 2048.
  - The periods wherein the system observes a shortage in capacity increases from 7 hours by the year 2028 to 77 hours by the year 2048 under normal operating conditions (N-0). With the ASP in service, this is reduced to 2 hours in the year 2048.
  - Without the ASP in service, maintaining adequate N-1 capacity becomes increasingly challenging at higher load levels. The ASP reduces the N-1 capacity risk from 2,800 MWh to 200 MWh by the year 2048.
  - For emergency, unplanned, or planned maintenance events involving the simultaneous outage of two or more subtransmission circuits in the Valley South System, the availability of tie-lines with the ASP reduces load at risk by greater than 70%.

- The ASP provides measurable operational flexibility improvement to address system needs under the HILP events in the Valley System. The current system configuration does not provide any benefit in this regard due to unavailable system ties.
- The ASP reduces the losses in the system from 52 GWh to 42 GWh in the year 2028 and from 61 GWh to 49 GWh in the year 2048.

Overall, the ASP demonstrated the robustness necessary to address the needs identified in the Valley service territory. By design, the project provides an alternative source of supply into the original Valley South service territory while effectively separating the system with tie-lines. This offers several advantages that can also help overcome the variability and uncertainty associated with the forecast peak load. The available flexibility through system tie-lines provides relief to system operations under both normal system conditions (increasing flexibility for planned maintenance outages) and for abnormal system conditions (unplanned outages) such as N-1, N-2, and HILP events that affect the region.

Findings and results reported in this document are based on publicly available information and the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

APPENDIX A: GLOSSARY

ASP: Alberhill System Project

BES: Bulk Electric System

CAIDI: Customer Average Interruption Duration Index

CAISO: California Independent System Operator

CPUC: California Public Utility Commission

DER: Distributed Energy Resources

LAR: Load at Risk

NERC: North American Electric Reliability Corporation

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

WECC: Western Electricity Coordinating Council

APPENDIX B: REFERENCES

1. Sub-transmission Planning Criteria and Guidelines, SCE 9/24/2015.
2. Decision Granting Petition to Modify Permit to Construct the Valley-Ivyglen 115 kV Sub-transmission Line Project and Holding Proceeding Open for Certificate of Public Convenience and Necessity for The Alberhill System Project, CPUC 8/31/2018.

APPENDIX C: RELIABILITY PERFORMANCE ADDITIONAL DETAILS

The cumulative benefits over a 10-year and 30-year horizon are presented in Table C-1 and Table C-2, respectively.

The present worth of benefits over a 10-year and 30-year horizon are presented in Table C-3 and Table C-4, respectively.

Table C-1. Cumulative Reliability Performance and Benefits with and without the ASP (10-year)

Category	Component	Cumulative Service Reliability Performance over 10-year Horizon	Cumulative Service Reliability Performance over 10-year Horizon	Cumulative Benefit over 10-year Horizon
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	356,842	291,522	65,319
N-1	Load at Risk (MWh)	274	0	274
N-1	IP (MW)	45	0	45
N-1	PFD (hr)	173	0	173
N-1	Flex 1 Load at Risk (MWh)	762,858	~~251,662~~103,783	659,076~~511,196~~
N-1	Flex 2-1 Average Load at Risk (MWh)	917,017	9,427	907,590
N-1	Flex 2-2 Average Load at Risk (MWh)	17,266	0	17,266
N-0	Load at Risk (MWh)	971	0	971
N-0	IP (MW)	288	0	288
N-0	PFD (hr)	35	0	35

Table C-2. Cumulative Reliability Performance and Benefits with and without the ASP (30-year)

Category	Component	Cumulative Service Reliability Performance over 30-year horizon (until 2048)	Cumulative Service Reliability Performance over 30-year horizon (until 2048)	Cumulative Benefit over 10-year horizon (until 2048)
		Baseline	***ASP***	***Baseline – ASP***
N-0	Losses (MWh)	1,494,322	1,216,714	277,608
N-1	Load at Risk (MWh)	21,684	1,047~~35~~	20,327~~649~~
N-1	IP (MW)	780	179	601
N-1	PFD (hr)	1,999	92	1,907
N-1	Flex 1 Load at Risk (MWh)	7,841,596	~~2,152,978~~1,817,470	~~5,688,618~~6,024,127
N-1	Flex 2-1 Average Load at Risk (MWh)	3,839,134	59,285	3,779,849
N-1	Flex 2-2 Average Load at Risk (MWh)	106,954	17	106,937
N-0	Load at Risk (MWh)	56,581	6	56,575
N-0	IP (MW)	4,056	4	4,053
N-0	PFD (hr)	815	4	811

Table C-3. Present Worth of Benefits with and without the ASP (10-year)

Category	Component	Present Worth of Service Reliability Performance over 10-year horizon (until 2028)	Present Worth of Service Reliability Performance over 10-year horizon (until 2028)	Present Worth of Benefits over 10-year horizon (till 2028)
		Baseline	***ASP***	***Baseline – ASP***
N-0	Losses (MWh)	247,375	202,121	45,254
N-1	Load at Risk (MWh)	173	0	173
N-1	IP (MW)	28	0	28
N-1	PFD (hr)	115	0	115
N-1	Flex 1 Load at Risk	497,134	~~166,962~~262,732	~~330,172~~434,402
N-1	Flex 2-1 Average Load at Risk (MWh)	636,100	6,453	629,646
N-1	Flex 2-2 Average Load at Risk (MWh)	11,822	0	11,822
N-0	Load at Risk (MWh)	606	0	606
N-0	IP (MW)	185	0	185
N-0	PFD (hr)	23	0	23

Table C-4. Present Worth Reliability Performance and Benefits with and without the ASP (30-year)

Category	Component	Present Worth of Service Reliability Performance over 30-year horizon (until 2048)	Present Worth of Service Reliability Performance over 30-year horizon (until 2048)	Present Worth of Benefits over 30-year horizon (until 2048)
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	490,137	399,753	90,384
N-1	Load at Risk (MWh)	3,054	112~~1~~	2,896~~943~~
N-1	IP (MW)	154	21	133
N-1	PFD (hr)	431	11	420
N-1	Flex 1 Load at Risk	1,806,240	~~525,050~~368,207	~~1,281,190~~1,438,032
N-1	Flex 2-1 Average Load at Risk (MWh)	1,259,315	16,083	1,243,232
N-1	Flex 2-2 Average Load at Risk (MWh)	29,196	2	29,195
N-0	Load at Risk (MWh)	8,658	0	8,657
N-0	IP (MW)	853	0	853
N-0	PFD (hr)	147	0	147

EXHIBIT G-2 (SECOND AMENDED)

Item G:

Cost/benefit analysis of several alternatives for:

- Enhancing reliability;
- Providing additional capacity including evaluation of energy storage, distributed energy resources, demand response or smart grid solutions.

Response to Item G

Revision 1.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This second amended motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 1

Revision Date: January 29, 2021

Summary of Revisions:

This revision modifies the cost benefit analysis to correct various errors and to clarify specific elements of the analysis. These changes are summarized in Supplemental Data Response to Item C[1] and in the attached revised report by Quanta Technologies.

[1] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

The attached report, prepared by Quanta Technology as a contractor to Southern California Edison (SCE), provides a cost-benefit analysis comparing several alternatives, including the Alberhill System Project (ASP). The identification of alternatives and methodology for this cost-benefit analysis are described in the Quanta Technology report and summarized with additional context in the response to DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C (Planning Study).

This cost-benefit analysis is one factor among many which informs and supports SCE's recommended solution[2]. Other factors integrated into SCE's analysis and informing SCE's recommended solution include, but are not limited to, benefits achieved in both the near and long term, potential environmental impacts, input from the general public and other stakeholders, and other risk considerations.

[2] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item I.

A Appendix: Quanta Cost Benefit Analysis

The Quanta Technology report, *Cost Benefit Analysis of Alternatives Version 2.1 (Second Amended Motion)*, which includes supporting cost benefit spreadsheets, is attached as Appendix A to this data submittal.

QUANTA
TECHNOLOGY

REPORT

Deliverable 3: Benefit Cost Analysis of Alternatives

PREPARED FOR

Southern California Edison (SCE)

DATE

June 15, 2021
Version 2.1(Errata)

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- Ehsan Raoufat
- Lee Willis

VERSION HISTORY:

Version	Date	Description
0.1	11/14/2019	First Draft
0.2	12/5/2019	Second Draft
1.0	1/3/2020	Final Report
2.0	1/27/2021	This revision corrects errors identified in the cost-benefit analysis results. Specifically: • Modifying the treatment of reliability benefits into Load at Risk (LAR) without probability weighting. This includes N-1, Flex -1 and Flex – 2 benefit categories. • For monetization purposes, reliability benefits are translated into Expected Energy Not Served (EENS) by consideration of average load at risk over duration of event. • Treatment of N-1 and N-2 probabilities associated with events in the Valley South System. • Treatment of probabilities associated with Flex-2-2 event. • Separating costs from two customer classes (commercial and residential) to three customer classes (Residential, Small & Medium Industries and Commercial)

		• Modifying the definition of Flex-2-1 and Flex-2-2 events to no longer constrain the events that drives the impact to occur at peak summer load conditions. The events now account for varying conditions throughout the years. • Updated Present Value of Revenue Requirements (PVRR) and Total costs associated with alternatives. • Removing consideration for SAIDI, SAIFI and CAIDI from the reliability metrics, which were previously provided for information purposes only. • Project scope and associated costs have been added to several alternatives to address N-1 line capacity violations that occur within the first ten years of the project planning horizon. • The market participation revenues for alternatives that include Battery Energy Storage Systems (BESS) were modified to include Resource Adequacy payments for the eight months of the year where the BESS would not be dedicated to the system reliability need. • Other minor editorial corrections and clarifications.
2.1(Second Amended Motion)	6/15/2021	This revision corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the reports are unaffected.

EXECUTIVE SUMMARY

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for SCE's Alberhill System Project (ASP) with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this study is to amend the ASP business case (including the benefit-cost analysis [BCA]) and alternative study using rigorous and data-driven methods.

A comprehensive framework was developed in coordination with the SCE study team to evaluate and rank the performance of alternatives. This evaluation is complemented by the development of load forecasts for the Valley South System planning area. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for the alternative projects is based on power flow studies in coordination with quantitative analysis to forecast the impacts of each alternative under evaluation, including the ASP. The projects' performance impacts are translated into key reliability metrics, representative of project performance over a 30-year horizon. Detailed analysis of the alternatives using benefit-cost and risk analysis frameworks to quantify the value of monetary benefits over the project horizon was conducted.

A total of 13 alternatives, including the ASP, were studied within this framework to evaluate their performance and contribution towards the project objectives. These alternatives were categorized as follows:

- Minimal investment
- Conventional
- Non-wires alternative (NWA)
- Hybrid (conventional plus NWA)

Highlights of the study are as follows:

- Consistent with industry-accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely conventional and spatial forecasts. (The load forecasting methodologies and findings are documented in detail within Section 2 of this report.)
  - The two forecasts have been developed consistent with the load-growth trend currently observed within the region and the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) projections for load-reducing technologies.
  - Sensitivity analysis was performed to address the uncertainties such as load-reducing technologies and the state of California's electrification goals.
  - Across the considered forecasts, the reliability need year was identified as 2022 (except for one sensitivity that identified 2021 as the need year).

  - The Effective PV Spatial load forecast is found to be the most consistent with the load-growth trend in the Valley South area. This forecast demonstrates a range of loading from 1,083 to 1,377 MVA from the year 2019 to 2048.
- Several reliability metrics were used to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that the ASP provides the highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resilience, and operational flexibility needs in the Valley South System. Considering the aggregated benefits under normal and emergency[1] conditions, the ASP results in 76 gigawatt-hours (GWh) of cumulative reduced unserved energy and $4.3 billion in cost savings to the end customers. The alternatives demonstrating the next-highest benefits (following the ASP) are SDG&E, SCE Orange County, and SDG&E with Centralized BESS (battery energy storage system) in Valley South.
- The BCA framework was implemented to evaluate and compare alternatives performance:
  - NWA solutions remained cost-effective only under reduced load forecast levels (e.g., reduced trend and low sensitivities of the conventional forecasts). Under the other forecasts, NWAs accrue significant costs over time due to the incremental storage sizing necessary to address the load growth in the Valley South system.
  - Conventional and hybrid alternatives can better satisfy project objectives and long-term reliability challenges in the system.
  - Menifee, ASP, SDG&E, and the Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Menifee and Valley South to Valley North have lower costs relative to the ASP while providing sizably lower benefits than ASP.
- The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. However, when it comes to the selection among alternatives, an incremental BCA should be conducted. Incremental BCA methodology warrants that the additional incremental cost is economically justifiable only if the benefit realized exceeds the incremental cost. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as type of project (reliability versus economic),environmental impact and risks.
- The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected.
- Risk analysis associated with forecast uncertainties demonstrates that:
  - The costs associated with the incremental size of the NWAs (to keep pace with peak load values) are substantial and result in reduced benefit-to-cost ratios.
  - The benefits attributed to operational flexibility from NWAs are negligible.
- The results of the reliability, benefit-cost, and risk analyses indicated that the ASP meets the project objectives over the 10-year horizon and ranks as the most favorable among the considered alternatives over a 30-year period.

[1] N-0, N-1, and operational flexibility.

Findings and results reported in this document are based on publicly available information along with the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

TABLE OF CONTENTS

List of Figures

List of Tables

List of Acronyms and Abbreviations

Term	Definition
AAEE	additional achievable energy efficiency
AAPV	additional achievable photovoltaic
AC	alternating current
ACSR	aluminum conductor steel-reinforced (cable)
AMI	advanced metering infrastructure
AS	ancillary service
ASP	Alberhill System Project
BCA	benefit-cost analysis
BES	bulk electric system
BESS	battery energy storage system
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CEC	California Energy Commission
CIGRE	International Council on Large Electric Systems
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
DA	day-ahead
DER	distributed energy resource
EENS	expected energy not served
ENA	Electrical Needs Area
EV	electric vehicle
GWh	gigawatt-hours
HILP	high-impact low-probability (event)
IERP	Integrated Energy Policy Report (of the California Energy Commission)
IP	interrupted power
ISO	independent system operator
LAR	load at risk

Term	Definition
LMDR	load modifying demand response
LMP	locational marginal price
LTELL	long-term emergency loading limits
MBCA	marginal benefit-to-cost analysis
MEA	mutually exclusive alternatives
NERC	North American Electric Reliability Corporation
NWA	non-wires alternative
O&M	operations and maintenance
PATHWAYS	a long-horizon energy model developed by Energy and Environmental Economics, Inc.
PFD	period of flexibility deficit
PV	photovoltaic
PVRR	present value of revenue requirements
RA	Resource Adequacy
RegDown	Regulation down
RegUp	Regulation up
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SOC	state of charge
STELL	short-term emergency loading limits
VO&M	variable operations and maintenance
VSSP	Valley South 115 kV Subtransmission Project
WACC	weighted aggregate cost of capital
WECC	Western Electricity Coordinating Council

1 INTRODUCTION

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV System. The overall objective of this analysis is to present a business case (including benefit-cost analysis [BCA]) justifying the appropriate project solution through data-driven quantitative methods and analysis.

In this section of the report, the project background, scope of work, study objective (including task breakdown), and study process have been outlined.

1.1 Project Background

Valley Substation is a 500/115 kV substation that serves electric demand in southwestern Riverside County. Valley Substation is split into two distinct 500/115 kV electrical systems: Valley North and Valley South. Each is served by two 500/115 kV, 560 MVA, three-phase transformers. The Valley South 115 kV System is not supplied power by any alternative means other than Valley Substation, nor does it have system tie-lines to adjacent 115 kV systems. In other words, this portion of the system is radially served by a single point of interconnection with the bulk electric system (BES) under the jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility,[2] and resilience needs of the Valley South System.

The Valley South 115 kV system Electrical Needs Area (ENA) consists of 14 distribution-level substations (115/12 kV substations). During the 2019–2028 forecast developed for peak demand, SCE identified an overload of the Valley South 500/115 kV transformer capacity by the year 2022 under normal operating conditions (N-0) and 1-in-5-year heat storm weather conditions. SCE has additionally identified the need to provide system tie-lines to improve reliability, resilience, and operational flexibility. To address these needs, the ASP was proposed. Figure 1-1 provides an overview of the project area.

Key features of this project are as follows:

- Construction of a 1,120 MVA 500/115 kV substation (Alberhill Substation).
- Construction of two 500 kV transmission line segments to connect the proposed Alberhill Substation by looping into the existing Serrano–Valley 500 kV transmission line.
- Construction of approximately 20 miles of 115 kV subtransmission line to modify the configuration of the existing Valley South System to allow for the transfer of five 115/12 kV distribution substations

[2] Flexibility or Operational Flexibility are used interchangeably in the context of this study. It is considered as the capability of the power system to absorb disturbances to maintain a secure operating state. It is used to bridge the gap between reliability and resilience needs in the system and overall planning objectives. Typically, system tie-lines allow for the operational flexibility to maintain service during unplanned equipment outages, during planned maintenance and construction activities, and to pre-emptively transfer load to avoid loss of service to affected customers. System tie-lines may effectively supplement transformation capacity by allowing the transfer of load to adjacent systems.

from the Valley South System to the new Alberhill System and to create 115 kV system tie-lines between the two systems.

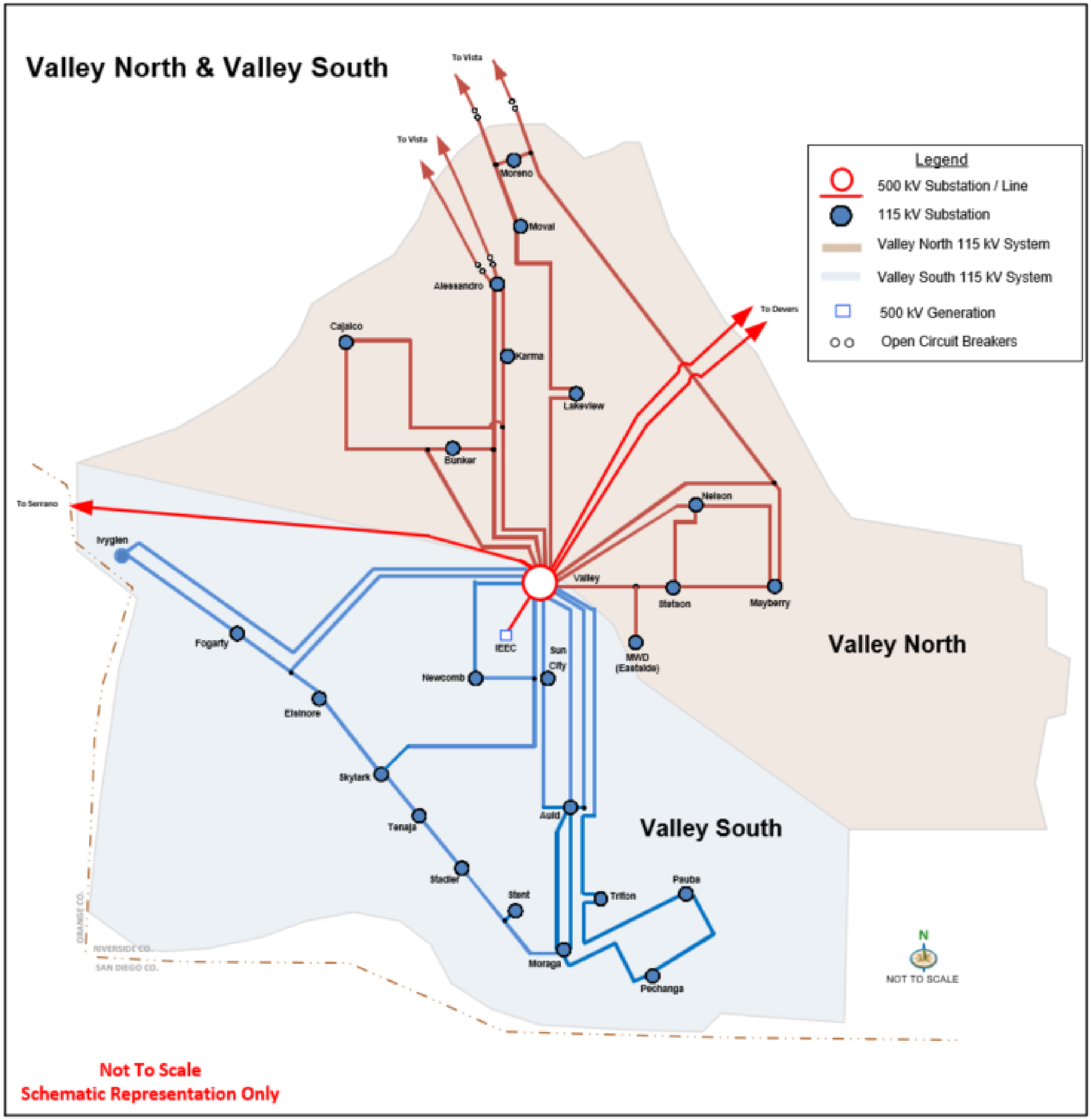


Figure 1-1. Valley Substation Service Areas[3]

SCE subsequently submitted an application to the CPUC seeking a Certificate of Public Convenience and Necessity (CPCN). During the final stage of the ASP proceeding, the CPUC directed SCE to provide

[3] Valley-Ivyglen and VSSP projects included [12]

additional analyses to justify the peak demand forecasts and reliability cases in support of justifying the project. The CPUC also directed SCE to provide a comparison of the proposed ASP to other potential system alternatives that may satisfy the stated project needs; these included, but were not limited to, energy storage, demand response, and distributed energy resources (DERs).

1.2 Scope of Work

Quanta Technology supported SCE in supplementing the existing record in the CPUC proceeding for the ASP with additional analyses including a forecast using industry-accepted methods of load forecast and additional alternatives including DERs to address any system needs established by the load forecasts to provide the necessary facilities to meet the capacity and reliability needs of the Valley South 500/115 kV system. The key scope items of the Quanta Technology analysis are detailed below:

1. Apply a rigorous, quantitative, data-driven approach to comprehensively present the business case justifying the appropriate project solution. The business case justification included a BCA of the alternatives considered based on the forecasted improvements in service reliability performance of the Valley South System. To this effect, Quanta Technology developed a load forecast for the Valley South System planning area using industry-accepted methods for estimating load growth and incorporating load-reduction programs due to energy efficiency, demand response, and behind-the-meter generation. Quanta Technology's forecasting exercise was developed independently of SCE's current forecasting methodology and practices; however, both SCE's and Quanta Technology's analysis incorporated the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) forecasts for the first 10 years through 2028.
2. Using power flow simulations and a quantitative review of project data, the forecasted impact of the proposed ASP on service reliability performance was estimated.
3. Identification of capital investments or operational changes to address reliability issues in the absence of construction of the proposed ASP or any other major projects requiring CPUC approval, along with the associated costs for such actions.
4. BCA of several system alternatives (including the proposed ASP, alternative substations and line configurations, energy storage, DER, demand response, and other smart-grid solutions or combinations thereof) for enhancing reliability and providing the required additional capacity.

The primary component of this work statement was to identify a number of system alternatives (e.g., alternative substation and line configurations, energy storage, DER, demand response, other smart-grid solutions, or combinations thereof [hybrid projects]) to satisfy the peak-demand load projections and reliability needs over a 30-year planning horizon. This was followed by a system analysis using a data-driven quantitative assessment of project performance, coupled with BCA of the proposed project and several of these alternatives, to allow objective comparison of their costs and benefits. Additionally, all system alternative designs were developed to satisfy the following project objectives[4] as stipulated by the project proceedings:

[4] For purposes of alternatives analysis SCE directed Quanta to refer to the original project objectives identified by SCE in its Proponents Environmental Assessment (PEA) that was filed with SCE's application because the project objectives as listed in the Final Environmental Impact Report (FEIR) identified that a solution must include a new 500/115 kV substation. During the ASP proceeding, the CPUC directing SCE to evaluate additional alternatives that…

1. Serve current and long-term projected electrical demand requirements in the SCE ENA.
2. Increase system operational flexibility and maintain system reliability (e.g., by creating system tie-lines that establish the ability to transfer substations located in the Valley South System).
3. Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity through the 10-year planning horizon.
4. Provide safe and reliable electrical service consistent with the SCE's Subtransmission Planning Criteria and Guidelines.
5. Increase electrical system reliability by constructing a project in a location suitable to serve the SCE ENA (i.e., the area served by the existing Valley South System).
6. Meet project needs while minimizing environmental impacts.
7. Meet project needs in a cost-effective manner.

1.3 Methodology

In order to accomplish the scope of this project, the following tasks were employed to meet the overall objectives of this effort:

- Task 1: Detailed Project Planning
- Task 2: Development of Load Forecast for the Valley South System
- Task 3: Reliability Assessment of ASP
- Task 4: Screening and Reliability Assessment of Alternatives
- Task 5: Benefit-Cost Analysis

The objective of each of the project tasks is detailed in the following subsections.

1.3.1 Task 1: Detailed Project Planning

The objective of this task was to develop a detailed and structured work plan that includes a description of the proposed load-forecasting methodology, overall study process, data needs, interim deliverables, and timeline of activities to meet the project deliverables. The key outcomes of this task were to review and finalize assumptions, methodology, metrics, and overall approach for the following key aspects of the project:

- Load forecasting methodology
- Data-driven, quantitative reliability metrics
- Reliability assessment and benefit-cost framework
- A detailed project plan including interim deliverables and schedule

…included DERs. To comprehensively perform this analysis would have been necessarily constrained by the project objectives as stated in the FEIR, thus reverting back to SCE's project objectives in its PEA (which did not specify a solution as requiring a new 500/115 kV substation) was most suitable to perform the required alternatives analysis.

1.3.2 Task 2: Development of Load Forecast for the Valley South System

The objective of this task was to develop a baseline load forecast representative of the 10-year horizon and a long-term forecast to account for the 30-year horizon. Forecasts have been developed for Valley North and Valley South Systems. The long-term forecasts are developed accounting for varying projections around energy efficiency, demand response, and behind-the-meter aggregations.

1.3.3 Task 3: Reliability Assessment of ASP

The objective of this task was to introduce the reliability assessment framework while describing the tools, formulation, and overall methodology. The proposed performance metrics are introduced, and their applicability has been described. Subsequently, the reliability framework was applied to the ASP and the overall project performance was evaluated.

1.3.4 Task 4: Screening and Reliability Assessment of Alternatives

The objective of this task was to analyze alternative projects (and their operational considerations) being considered to address the reliability needs in the absence of the ASP. Through a screening process, the selected set of alternative projects are evaluated using the reliability framework to quantify their performance.

1.3.5 Task 5: Benefit-Cost Analysis

The objective of this task was to perform a BCA of the ASP along with the list of system alternatives from Task 4. This analysis intended to compare the project alternatives using the quantitative reliability metrics developed in Task 1 along with rigorous cost and risk analysis that will be required to justify the business case of each alternative for meeting the load growth and reliability needs of the Valley South System.

1.4 Report Organization

This report has been organized consistent with the tasks outlined in Section 1.3. The report has been separated into several sections that individually address each task item. The intent of this breakdown is to capture, in detail, the essential elements of the reliability and benefit-cost framework.

In Section 2 of this report, the long-term spatial load forecast is discussed. This section is complementary to Quanta Technology's load forecast report [1], which focused on the near-term load forecast and describes the technical details behind the spatial load forecasting methodology.

Section 3 of this report presents the overall framework for reliability and benefit-cost evaluation. This highlights the study methodology, assumptions, and describes key processes involved in the analysis.

In Sections 4 and 5, the reliability evaluation framework is applied to the ASP and selected alternatives. Each of the forecasts developed in Task 2 is applied to evaluate the alternative's performance.

Section 6 presents the results from the BCA and deterministic risk assessment.

Section 7 presents the report conclusions and is followed by applicable references (Section 8) and an appendix (Section 9) that provides the N-2 probabilities associated with circuits that share a common tower structures.

2 LONG-TERM SPATIAL LOAD FORECAST

The spatial load forecast for the Valley North and Valley South Systems of the greater SCE system was developed for a long-term period of 30 years, covering from 2019 to 2048. The horizon year of 2048 assumed all general plan land use maps for Valley North and Valley South communities are designed for the 30-year horizon. Forecast results up to the year 2028 were presented in a separate report [1]. This forecast was constructed from a baseload forecast and incorporated DER development according to CEC's 2018 IEPR [2] and SCE's dependable photovoltaic (PV) disaggregation. The result was a disaggregated effective PV forecast that expanded the 10-year PV forecast for the Valley North and Valley South regions to the 30-year timeframe. This section describes the methodology used to develop the additional 20 years of the load forecast (2029–2048) and considers three DER development scenarios.

2.1 Base spatial load forecast

The spatial load forecasting method developed by Quanta Technology was presented in [1], where base forecast results were shown up to the year 2028. This spatial forecast methodology is based on a 30-year horizon year,[5] and results were obtained for the entire period.

These forecast results are representative of the natural load growth resulting from incremental use of electricity by existing customers and new customer additions as indicated by future land use plans. The sum of these two factors provides the base spatial forecast that does not include the effects of future DER developments. Embedded within these results are the current levels of DER adoption observed by the base forecast. The results are summarized in Table 2-1. Further details on the spatial load forecast methodology, can be found in [1].

Table 2-1. Base Spatial Load Forecast without Additional Impacts of Future DER

Year	Spatial Valley South (No added DER) [MVA]	Spatial Valley North (No added DER) [MVA]
2018	1068	769
2019	1092	787
2020	1116	804
2021	1142	825
2022	1162	845
2023	1181	857
2024	1193	866
2025	1205	874

[5] The 30-year horizon year was selected as a typical long-term planning range that allows accommodating such things as the time required for regulatory licensing and permitting activities as well as lead times and financial budgeting for utility equipment and construction as required.

Year	Spatial Valley South (No added DER) [MVA]	Spatial Valley North (No added DER) [MVA]
2026	1217	882
2027	1229	893
2028	1242	904
2029	1254	915
2030	1267	925
2031	1280	938
2032	1293	950
2033	1306	963
2034	1319	975
2035	1331	989
2036	1344	1002
2037	1356	1015
2038	1369	1029
2039	1380	1042
2040	1392	1055
2041	1404	1068
2042	1415	1081
2043	1425	1093
2044	1436	1105
2045	1446	1117
2046	1456	1129
2047	1465	1140
2048	1474	1150

2.2 DER Development from 2019 to 2028

Based on IEPR 2018, SCE provided disaggregated DER forecasts to the level of the Valley South and Valley North systems. These DER forecasts covered from 2019 to 2028 and included additional achievable energy efficiency (AAEE), additional achievable photovoltaic (AAPV), electric vehicles (EVs), energy storage, and load modifying demand response (LMDR) categories.

2.2.1 AAPV Disaggregation

For AAPV, SCE provided two scenarios: 1) SCE Effective PV and 2) PVWatts. The final load forecast presented in [1] considers the SCE Effective PV scenario as the most likely scenario during the period from 2019 to 2028. AAPV values based on the SCE Effective PV forecast and AAPV values based on PVWatts impacts on peak load reduction are shown in Table 2-2.

Table 2-2. Disaggregated Forecasted Peak Modifying AAPV from 2019 to 2028

	DER Type (units in MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	AAPV SCE Effective PV	-4.9	-4.9	-4.9	-4.9	-4.9	-4.5	-4.0	-3.7	-3.7	-2.9
	AAPV PVWatts	-7.7	-7.6	-7.6	-7.5	-7.4	-6.8	-6.2	-5.8	-5.6	-4.3
Valley South	AAPV SCE Effective PV	-5.7	-5.0	-4.2	-3.4	-3.0	-2.8	-2.7	-2.4	-2.1	-1.9
	AAPV PVWatts	-8.9	-8.7	-8.6	-8.4	-7.8	-7.0	-7.0	-6.3	-5.6	-4.8

2.2.2 Disaggregation of Other DER Categories

Based on the 2018 IEPR, SCE also provided disaggregated DER forecasts for AAEE, EVs, energy storage, and LMDR categories. The forecasted peak-modifying amounts of DER are shown in Table 2-3.

Table 2-3. Disaggregated Forecasted Peak-Modifying DER from 2019 to 2028

	DER Type (units in MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	Electric Vehicle	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.2	0.2	0.3
	AAEE	-2.3	-2.1	-2.6	-2.8	-3.2	-2.9	-2.8	-2.7	-2.8	-2.9
	Energy Storage	-0.5	-0.1	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1
	LMDR	0.0	-0.5	0.0	-0.1	-0.2	-0.1	-0.1	0.0	0.0	0.0
Valley South	Electric Vehicle	0.8	0.9	0.8	0.6	0.7	0.6	0.6	0.4	0.4	0.4
	AAEE	-3.4	-2.9	-3.6	-2.6	-3.0	-2.8	-2.7	-2.5	-2.6	-2.8
	Energy Storage	-1.0	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1
	LMDR	0.6	-1.4	0.0	-0.2	-0.2	-0.1	-0.1	0.0	0.0	0.0

2.3 Forecasted DER Development 2029–2048

In order to obtain a long-term spatial forecast that considers the impacts of DERs, it is necessary to have DER forecasts that extend to the year 2048. The estimation of DER from the year 2029 until the year 2048 has been performed as described in the following subsections.

2.3.1 AAPV Growth from 2029 to 2048

Growth rates of generation forecasts for solar and rooftop PV have been taken from the California PATHWAYS model [3], on its CEC 2050 scenario. The same yearly growth rates for the state of California have been applied to the AAPV forecasts of Table 2-2, starting from the year 2029, to generate an estimation of the AAPV in the Valley South and Valley North Systems up to the year 2048. The estimated AAPV at the Valley South and Valley North system level for the AAPV Effective PV and the AAPV PVWatts scenarios are shown in Table 2-4 and Table 2-5.

Table 2-4. California (CA) PATHWAYS CEC 2050 Case for the Solar Generation [MVA], and Estimated AAPV SCE Effective PV (in MVA) at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA Solar	75.7	80.6	86	92.1	95.8	100	105	111	117	124	132	139	146	152	157	162	167	172	176	179	183
CA PV	29.9	33	36.4	37.5	38.6	39.7	40.8	41.9	42.9	44	45.1	46.2	47.3	48.3	49.4	50.5	51.6	52.7	53.8	54.8	55.9
CA Total	106	114	122	130	134	140	146	153	160	168	177	185	193	200	207	213	219	225	230	234	239
AAPV Valley North	-2.9	-2.7	-2.5	-2.3	-2.2	-2.1	-2.1	-2	-1.9	-1.8	-1.7	-1.6	-1.5	-1.5	-1.4	-1.4	-1.3	-1.3	-1.3	-1.3	-1.2
AAPV Valley South	-1.9	-1.8	-1.6	-1.5	-1.5	-1.4	-1.4	-1.3	-1.2	-1.2	-1.1	-1.1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8

Table 2-5. California (CA) PATHWAYS CEC 2050 Case for the Solar Generation [MVA], and Estimated AAPV PVWatts (in MVA) at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA Solar	75.7	80.6	86	92.1	95.8	100	105	111	118	124	132	139	146	152	157	162	167	172	176	180	183
CA PV	29.9	33	36.5	37.5	38.6	39.7	40.8	41.9	42.9	44	45.1	46.2	47.3	48.4	49.4	50.5	51.6	52.7	53.8	54.8	55.9
CA Total	106	114	123	130	134	140	146	153	160	168	177	185	193	200	207	213	219	225	230	234	239
AAPV Valley North	-4.3	-4	-3.6	-3.4	-3.3	-3.2	-3	-2.9	-2.7	-2.6	-2.5	-2.4	-2.3	-2.2	-2.1	-2	-2	-1.9	-1.9	-1.9	-1.8
AAPV Valley South	-4.8	-4.5	-4.1	-3.9	-3.7	-3.6	-3.4	-3.3	-3.1	-3	-2.8	-2.7	-2.6	-2.5	-2.4	-2.3	-2.2	-2.2	-2.1	-2.1	-2.1

As a third scenario for AAPV growth after 2028, a compound annual growth rate (CAGR) of 3% was used as a reasonable expectation for future AAPV after the year 2028. This is based on CEC IEPR PV forecast observations that around 2022 the natural adoption of PV starts to show plateau. The additional growth from zero net energy or new home installations is expected to be relatively flat for every year. That means it will not generate higher growth rates for PV forecast in the longer term. The reasonable growth rate for the disaggregated PV forecast going beyond 2028 is about -3%. The resulting estimations of peak reducing capabilities are shown in Table 2-6.

Table 2-6. Estimated AAPV PVWatts (in MVA) at Valley South and Valley North a -3% CAGR

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
AAPV Valley North	-2.9	-2.8	-2.7	-2.6	-2.6	-2.5	-2.4	-2.3	-2.3	-2.2	-2.1	-2.1	-2	-2	-1.9	-1.8	-1.8	-1.7	-1.7	-1.6	-1.6
AAPV Valley South	-1.9	-1.9	-1.8	-1.7	-1.7	-1.6	-1.6	-1.5	-1.5	-1.5	-1.4	-1.4	-1.3	-1.3	-1.2	-1.2	-1.2	-1.1	-1.1	-1.1	-1

Figure 2-1 and Figure 2-2 show the AAPV forecasted growth scenarios for Valley South and Valley North, respectively.

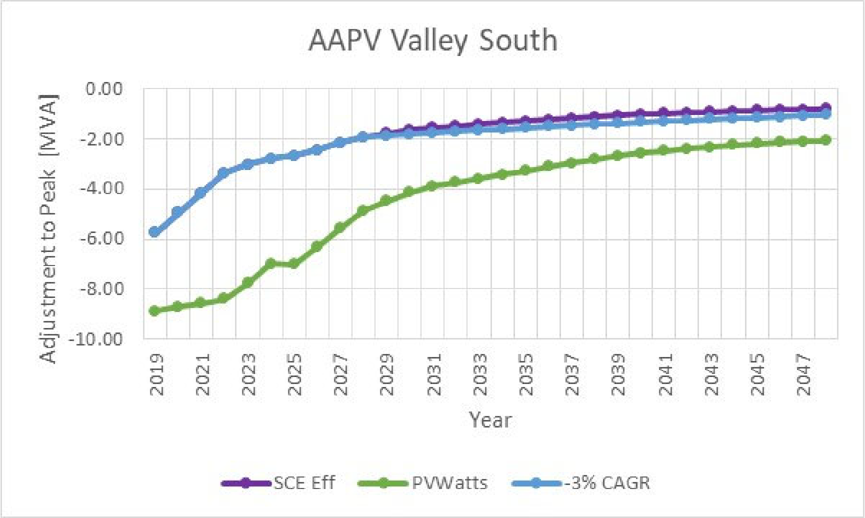


Figure 2-1. AAPV Forecasted Growth Scenarios for Valley South

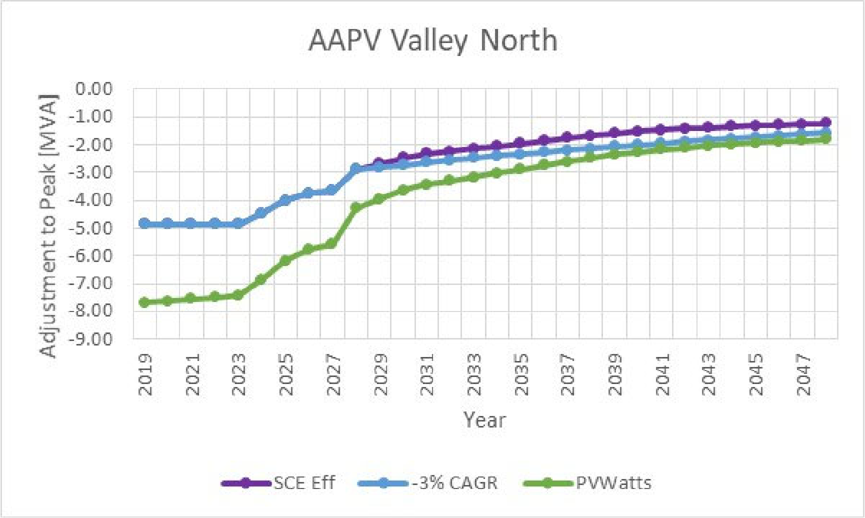


Figure 2-2. AAPV Forecasted Growth Scenarios for Valley North

2.3.2 EV Growth from 2029 to 2048

The EV disaggregated forecast of Table 2-3 was extended until the year 2048 by using growth rates of subsector electric demands for light-duty vehicles, taken from the California PATHWAYS model, on its CEC 2050 scenario. The same yearly growth rates for the state of California have been applied to the EV forecast of Table 2-3, starting from the year 2028. The estimated EV load at the Valley South and the Valley North System are shown in Table 2-7.

Table 2-7. California PATHWAYS CEC 2050 Case for the Light EV Load (in MVA), and Estimated EV [MVA] at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA EV	10.1	11.8	14	16.5	19.4	22.5	25.5	28.3	30.8	33.2	35.5	37.5	39.4	41.3	43	44.5	45.8	46.9	47.7	48.4	48.8
EV Valley North	0.28	0.32	0.38	0.45	0.53	0.62	0.7	0.78	0.85	0.91	0.97	1.03	1.08	1.13	1.18	1.22	1.26	1.29	1.31	1.33	1.34
EV Valley South	0.43	0.5	0.6	0.7	0.83	0.96	1.09	1.2	1.31	1.42	1.51	1.6	1.68	1.76	1.83	1.9	1.95	2	2.03	2.06	2.08

Figure 2-3 and Figure 2-4 show the forecasted amounts of peak-enhancing electric vehicle loads for Valley South and Valley North.

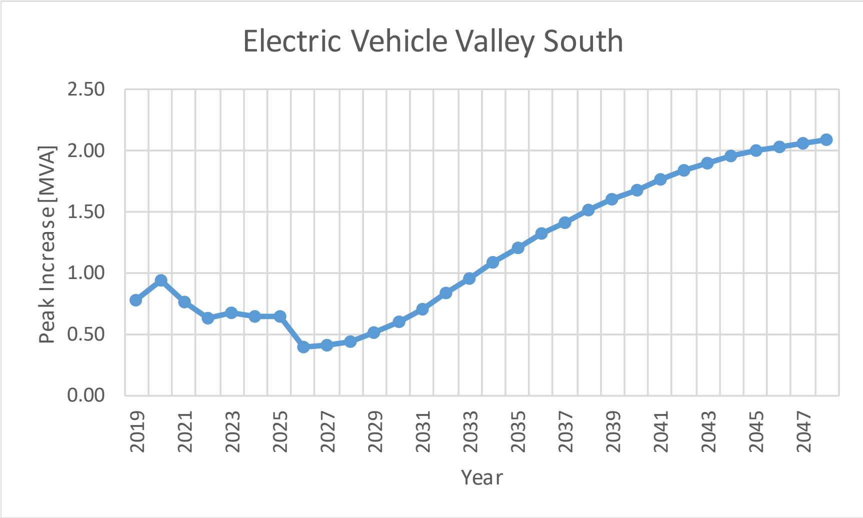


Figure 2-3. EV Forecasted Growth for Valley South

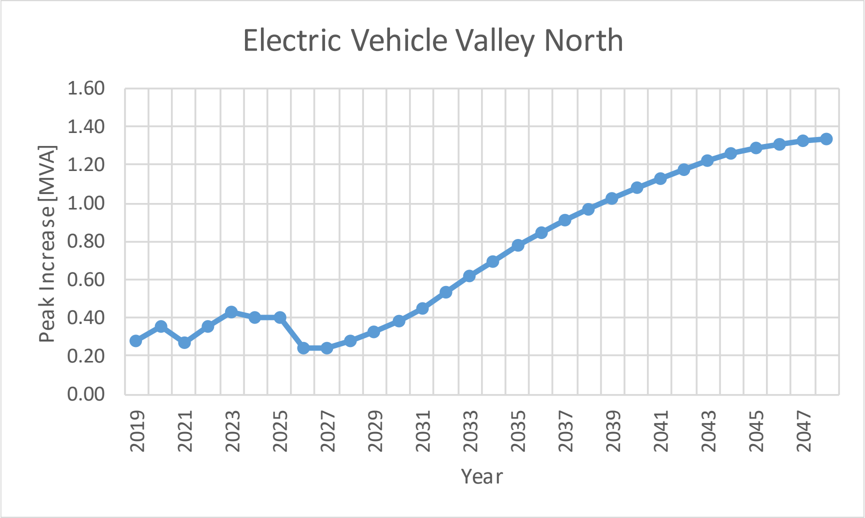


Figure 2-4. EV Forecasted Growth for Valley North

2.3.3 Energy Efficiency Growth from 2029 to 2048

The energy efficiency disaggregated forecast of Table 2-3 was extended until the year 2048 based on the criteria that after 2028 the load reductions in energy efficiency are expected to be close to 21% of the forecasted load growth of each year. Additionally, it is considered that energy efficiency load reductions will predominantly take place in residential loads, which are approximately 40% of the Valley South system load and approximately 36% of the Valley North System load. The resulting extended forecast for energy efficiency is shown in Table 2-8.

Table 2-8. Estimated Growth of Peak-Reducing Energy Efficiency at Valley South and Valley North (in MVA)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
EE Valley North	-0.8	-0.9	-0.9	-0.9	-0.9	-1	-1	-1	-1	-1	-1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8
EE Valley South	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1	-1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.7	-0.7	-0.7

Figure 2-5 and Figure 2-6 show the forecasted amounts of peak-reducing Energy Efficiency effect for Valley South and Valley North.

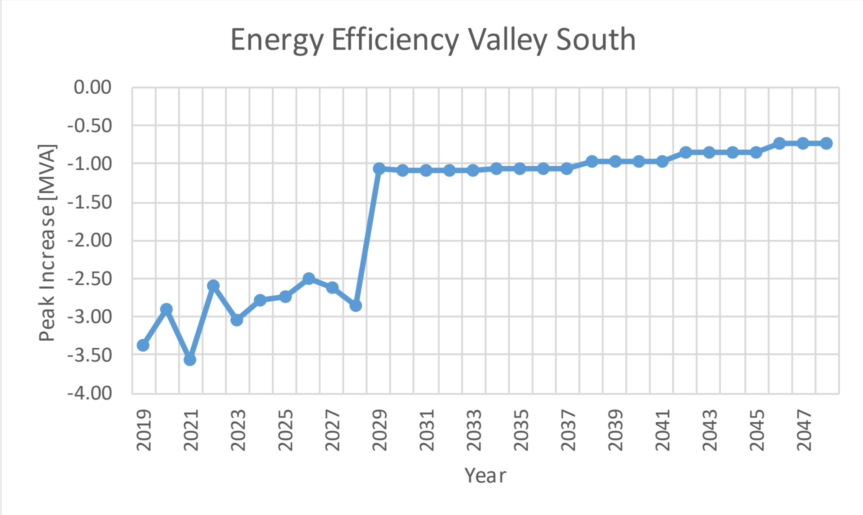


Figure 2-5. Energy Efficiency Forecasted Growth for Valley South

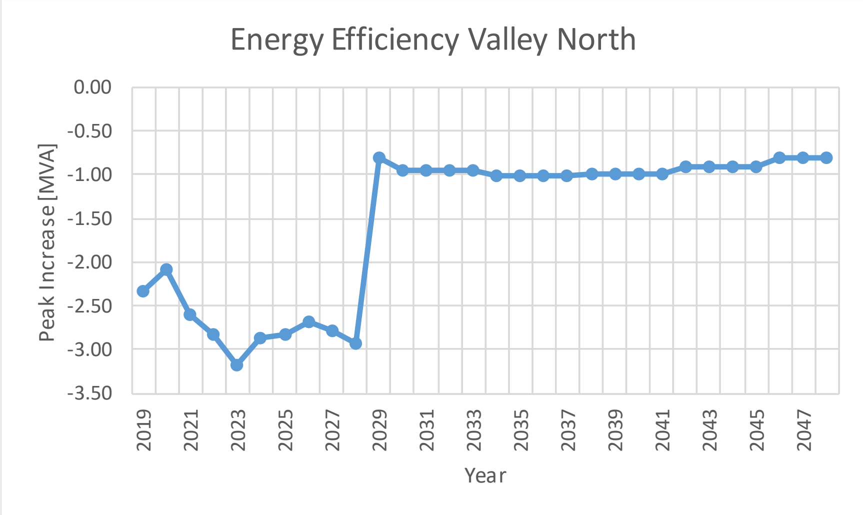


Figure 2-6. Energy Efficiency Forecasted Growth for Valley North

2.3.4 Energy Storage Growth from 2029 to 2048

SCE provided an energy storage outlook for the entire SCE service territory. This outlook estimated an approximated total of 4,300 MVA of energy storage by the year 2048. By SCE criteria, it was estimated that 60% of this storage would be associated with residential customers, of which approximately 5% would be located in the Valley South System and approximately 20% of it would have a peak reduction effect. These considerations lead to an estimated peak-reducing amount of cumulated energy storage of 26 MVA (or an additional 23.6 MVA after 2028) by 2048 for the Valley South System. Similar considerations lead to additional cumulated 15.5 MVA of peak reducing energy storage for the Valley North System.

A CAGR of energy storage was identified for each area (Valley North and Valley South) so that the year 2048 estimated values were achieved. The resulting CAGR for the Valley South system is 17.98%, and the same for Valley North is 14.39%. Table 2-9 summarizes the resulting estimated peak-reducing amounts of energy storage for the Valley South and Valley North Systems.

Table 2-9 Estimated Growth of Peak-Reducing Energy Storage at Valley South and Valley North (in MVA)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Storage Valley North	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.4	-0.4	-0.5	-0.5	-0.6	-0.7	-0.8	-0.9	-1.1	-1.2	-1.4	-1.6	-1.8	-2.1
Storage Valley South	-0.2	-0.2	-0.2	-0.3	-0.3	-0.4	-0.4	-0.5	-0.6	-0.7	-0.8	-1	-1.2	-1.4	-1.6	-1.9	-2.3	-2.7	-3.2	-3.7

Figure 2-7. and Figure 2-8 show the forecasted amounts of peak-reducing Energy Storage effect for the Valley South and Valley North Systems.

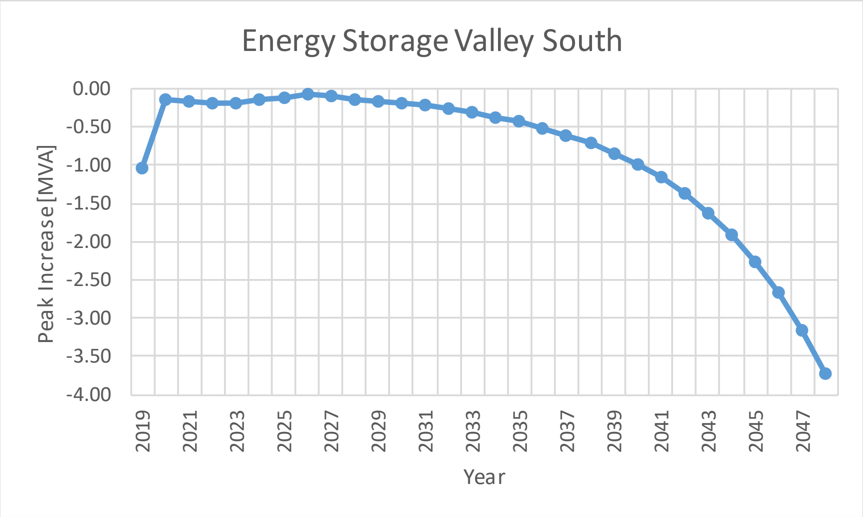


Figure 2-7. Energy Storage Forecasted Growth for Valley South

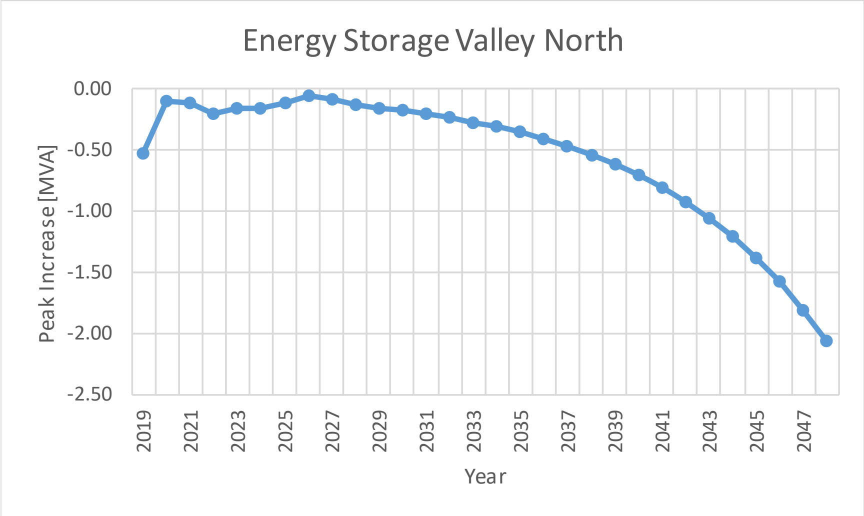


Figure 2-8. Energy Storage Forecasted Growth for Valley North

2.3.5 Demand Response Growth from 2029 to 2048

According to the demand response trends extracted from Table 2-3, the effects of demand response were considered negligible after the year 2028.

2.4 Valley South and Valley North Long-Term Forecast Results

The peak modifying effects for future DER discussed in the previous sections were aggregated and applied to the base spatial load forecast of Section 2.1 to develop long-term load forecast results for Valley South and Valley North. The resulting forecast scenarios are summarized in Table 2-10 and Figure 2-9 for the Valley South system and in Table 2-11 and Figure 2-10 for the Valley North System.

Table 2-10. Final Results of the Spatial Forecast for Valley South, Considering Three AAPV Growth Alternatives after the Year 2028

Year	Spatial Valley South (no added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2018	1068	1068	1068	1068
2019	1092	1083	1083	1083
2020	1116	1099	1099	1099
2021	1142	1118	1118	1118
2022	1162	1132	1132	1132
2023	1181	1146	1146	1146
2024	1193	1152	1152	1152
2025	1205	1159	1159	1159

Year	Spatial Valley South (no added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2026	1217	1166	1166	1166
2027	1229	1174	1174	1174
2028	1242	1183	1183	1183
2029	1254	1193	1177	1193
2030	1267	1203	1172	1203
2031	1280	1214	1166	1213
2032	1293	1225	1175	1224
2033	1306	1236	1184	1235
2034	1319	1247	1193	1246
2035	1331	1258	1202	1257
2036	1344	1269	1211	1267
2037	1356	1280	1221	1278
2038	1369	1291	1230	1289
2039	1380	1302	1239	1299
2040	1392	1312	1248	1309
2041	1404	1322	1256	1319
2042	1415	1333	1265	1329
2043	1425	1341	1272	1337
2044	1436	1350	1280	1346
2045	1446	1358	1287	1354
2046	1456	1366	1293	1361
2047	1465	1372	1298	1367
2048	1474	1378	1302	1373

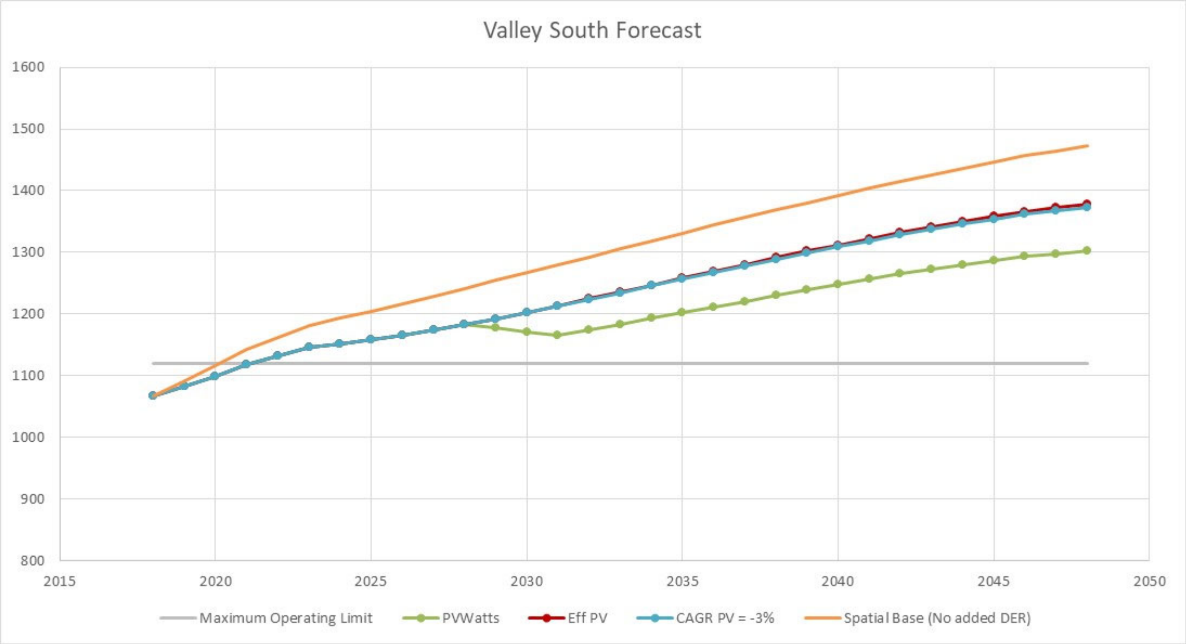


Figure 2-9. Final Results of the Spatial Forecast for Valley South, Considering Three AAPV Growth Alternatives after the Year 2028

Table 2-11. Final Results of the Spatial Forecast for Valley North, Considering Three AAPV Growth Alternatives after the Year 2028

Year	Spatial Valley North (No added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2018	769	769	769	769
2019	787	779	779	779
2020	804	789	789	789
2021	825	803	803	803
2022	845	816	816	816
2023	857	820	820	820
2024	866	821	821	821
2025	874	823	823	823
2026	882	825	825	825
2027	893	829	829	829
2028	904	834	834	834
2029	915	842	834	842

Year	Spatial Valley North (No added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2030	925	849	833	849
2031	938	859	832	858
2032	950	868	840	867
2033	963	878	849	877
2034	975	888	858	886
2035	989	899	868	897
2036	1002	910	878	907
2037	1015	921	888	918
2038	1029	932	898	928
2039	1042	943	908	939
2040	1055	954	919	949
2041	1068	964	929	960
2042	1081	975	939	970
2043	1093	985	948	980
2044	1105	995	958	989
2045	1117	1005	967	998
2046	1129	1015	976	1008
2047	1140	1023	983	1015
2048	1150	1031	991	1023

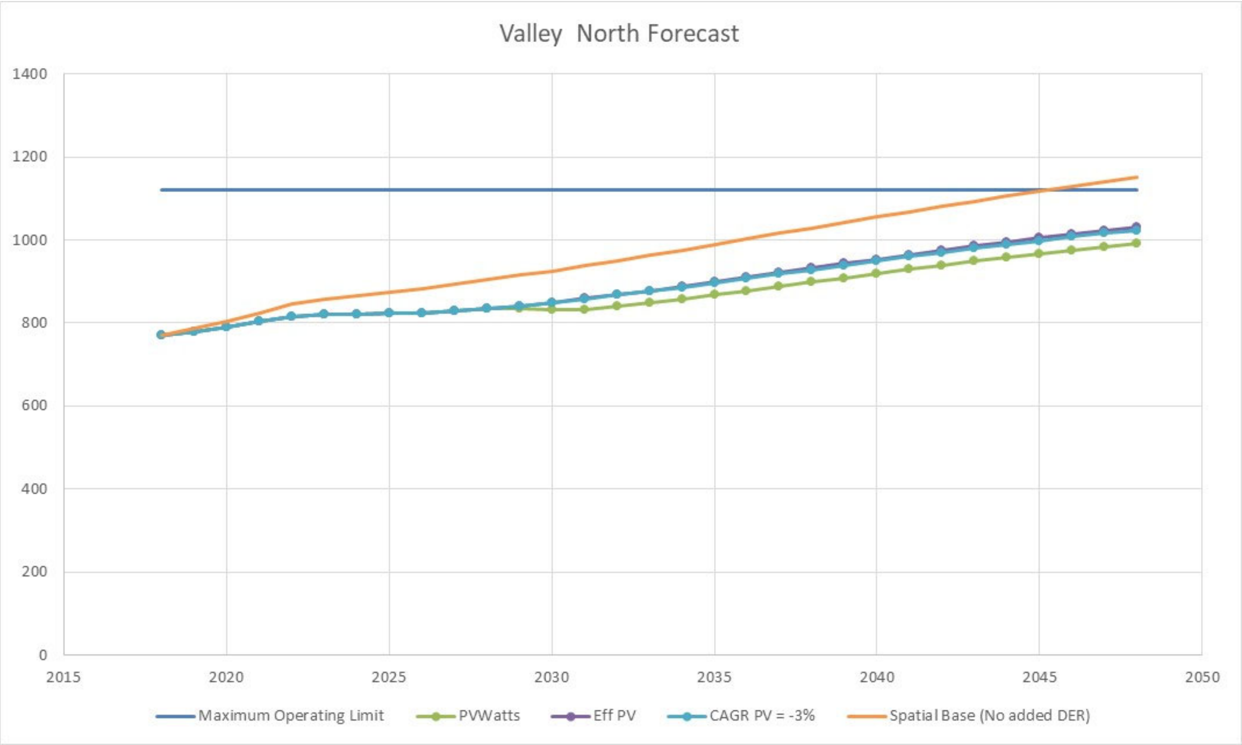


Figure 2-10. Final Results of the Spatial Forecast for Valley North, Considering Three AAPV Growth Alternatives after the Year 2028

3 RELIABILITY ASSESSMENT AND BENEFIT-COST FRAMEWORK

3.1 Introduction

The objective of this framework is to facilitate the evaluation of project performance and benefits relative to the baseline scenario (i.e., no project in service). The projects under consideration include the ASP and proposed alternatives discussed further in Sections 4 and5. Within the framework of this analysis, reliability, capacity, operational flexibility, and resilience benefits have been quantified.

In order to successfully evaluate the benefit of a potential project in the Valley South System, the project's performance must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance
2. To compare project performance to the baseline scenario (no project in service)
3. To establish a basis to value the performance of projects against overall objectives
4. To take into consideration the benefits or impacts of operational flexibility and resilience (high-impact low-probability events [HILP])
5. To compare and provide guidance for comparing the relative performance of each alternative as compared to others.

Within the scope of the developed metrics, the key project objectives presented earlier, are categorized and reviewed as follows:

- **Capacity**
  - Serve current and long-term projected electrical demand requirements in the SCE ENA.
  - Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through not only the 10-year planning horizon but also that of a longer-term horizon that identifies needs beyond 10 years, which would allow for an appropriate comparison of alternatives that have different useful lifespan horizons.

- **Reliability**
  - Provide safe and reliable electrical service consistent with the SCE Subtransmission Planning Criteria and Guidelines.
  - Increase electrical system reliability by constructing a project in a location suitable to serve the ENA (i.e., the area served by the existing Valley South System).

- **Operational Flexibility and Resilience**
  - Increase system operational flexibility and maintain system reliability (e.g., by creating system tie-lines that establish the ability to transfer substations from the current Valley South System and to address system operational capacity needs under normal and contingency (N-1) conditions.

3.2 Reliability Framework and Study Assumptions

In order to develop a framework to effectively evaluate the performance of a project, the overall study methodology was broken down into the following elements:

1. Develop metrics to establish project performance
2. Quantify the project performance using commercial power flow software
3. Establish a platform to evaluate monetized and non-monetized project benefits
4. Utilize tools such as benefit-to-cost ratio, incremental BCA, and $/unit benefit to substantiate alternative selection and conclusions.

Each of the above areas is further detailed throughout this section.

3.2.1 Study Inputs

SCE provided Quanta Technology with information pertinent to the Valley South, Valley North, and the proposed ASP systems. This information encompassed the following data:

1. GE PSLF power flow models for Valley South and Valley North Systems:
    a. 2018 system configuration (current system)
    b. 2021 system configuration (Valley–Ivyglen [4] and VSSP [5] projects modeled and included)
    c. 2022 system configuration (with the ASP in service)
2. Substation layout diagrams representing the Valley Substation
3. Impedance drawings for the Valley South and Valley North Systems depicting the line ratings and configurations
4. Single-line diagram of the Valley South and Valley North Systems
5. Contingency processor tools to develop relevant study contingencies to be considered for each system configuration
6. 8,760 load shape of the Valley South System
7. Advanced metering infrastructure (AMI) data for metered customers in the Valley South and Valley North Systems with circuit and substation association, annual consumption amount, and peak demand use

The reliability assessment utilizes the load forecasts developed for Valley South and Valley North System service territories to evaluate the performance of the system for future planning horizons. The developed forecasts are detailed in Section 2 of this report. The primary forecasts under consideration for reliability analysis are the Effective PV (§2.4) along with associated sensitivities, the Spatial Base Forecast (§2.4), and PVWatts (§2.4). The Effective PV forecast is expected to most closely resemble the levels of growth anticipated in the Valley South System. The developed forecasts take into consideration the variabilities in future developments of PV, EV, energy efficiency, energy storage, and LMDR.

The load forecasts for Valley South are presented in Figure 3-1, which demonstrate system deficiency in (need) year 2022 (Effective PV and PVWatts) and 2021 (Spatial Base), where the loading on the Valley South transformers exceed maximum operating limits (1,120 MVA). Figure 3-2, presents the representative load forecast for Valley North where the loading on the Valley North transformers exceed maximum operating limits (1,120 MVA) by 2045 in the Spatial Base forecast.

Benefits begin to accrue coincident with the project need year. For purposes of this assessment, it is assumed that the project will be in service by this year, and benefits accrue from the need year to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

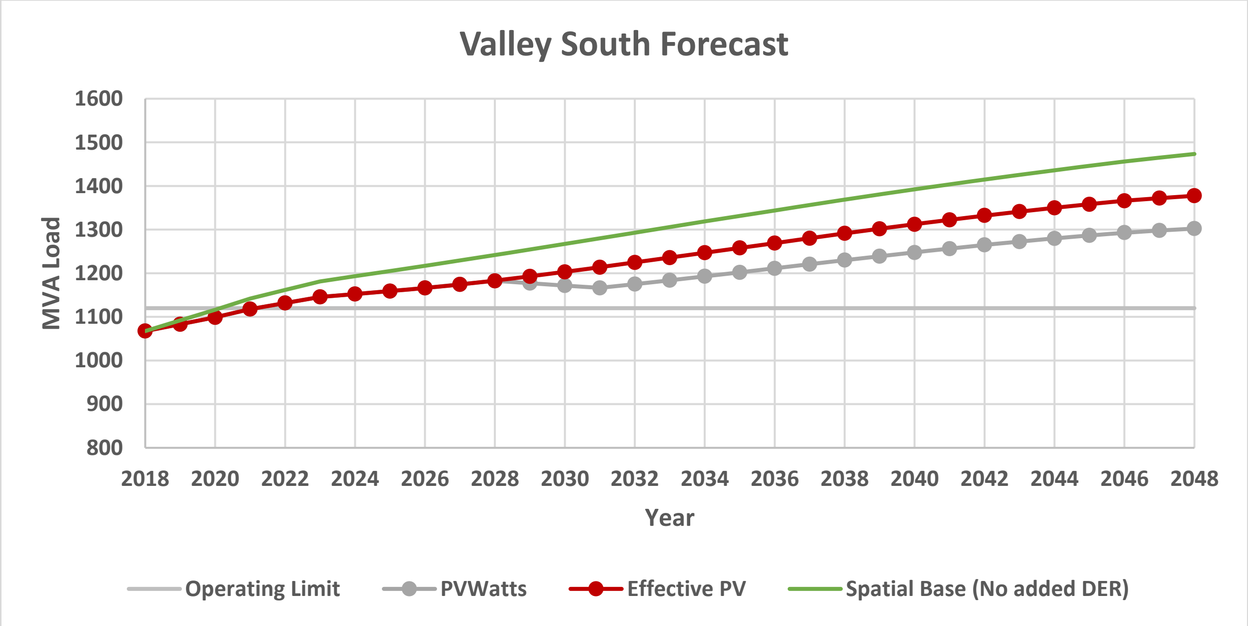


Figure 3-1. Valley South Load Forecast (Peak)

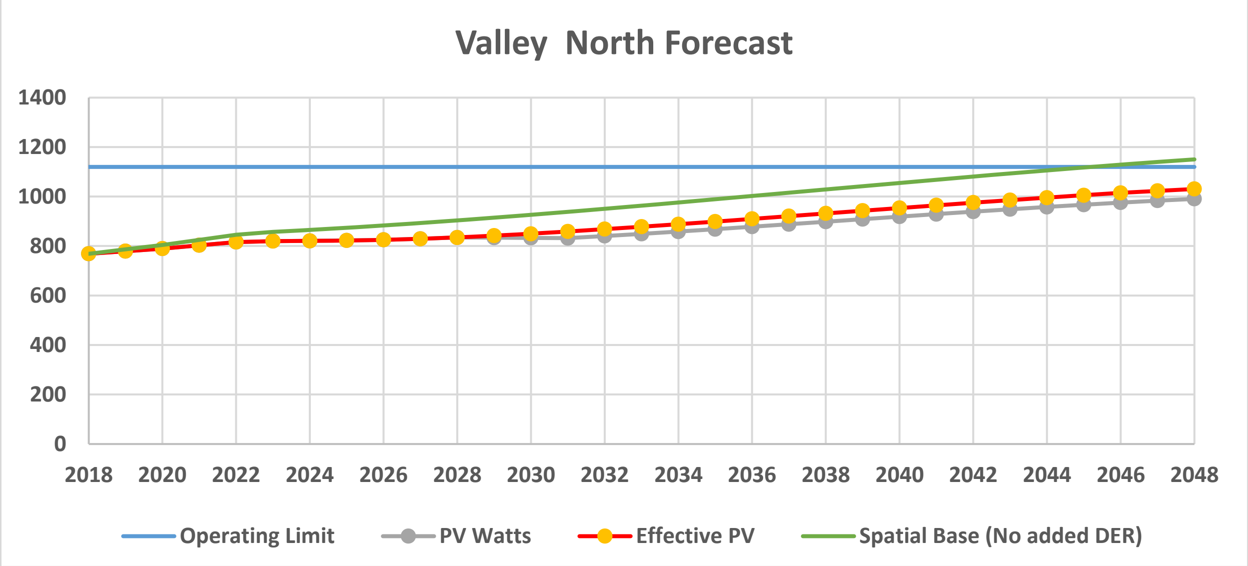


Figure 3-2. Valley North Load Forecast (Peak)

System configuration for the years 2018 (current), 2021, and 2022 are depicted in Figure 3-3 through Figure 3-5.

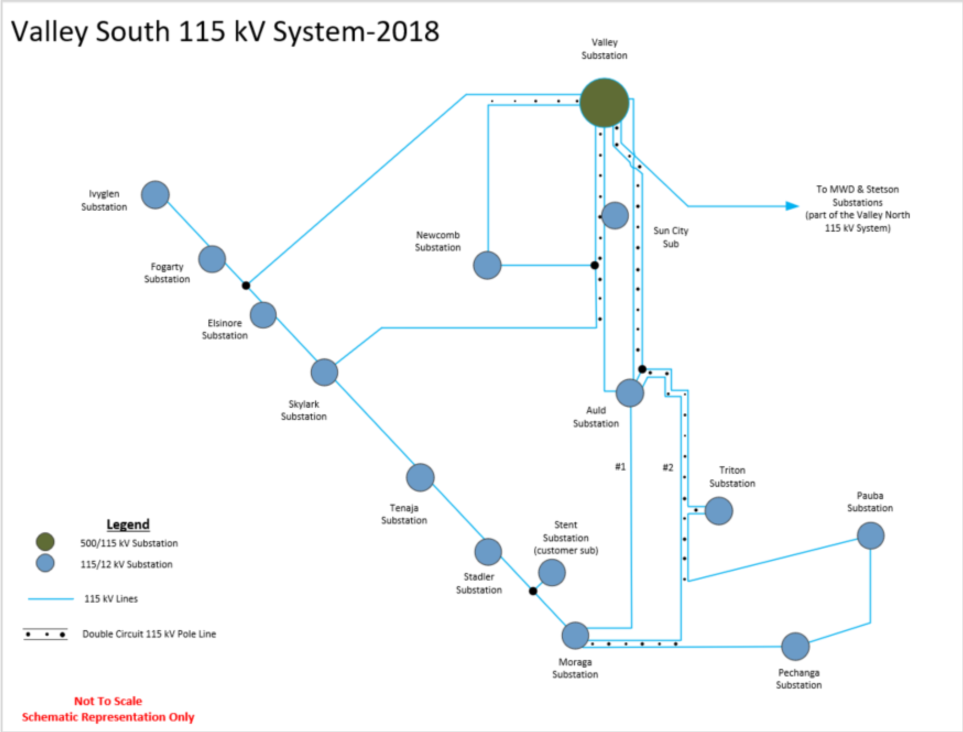


Figure 3-3. Valley South System Current Configuration (2018)

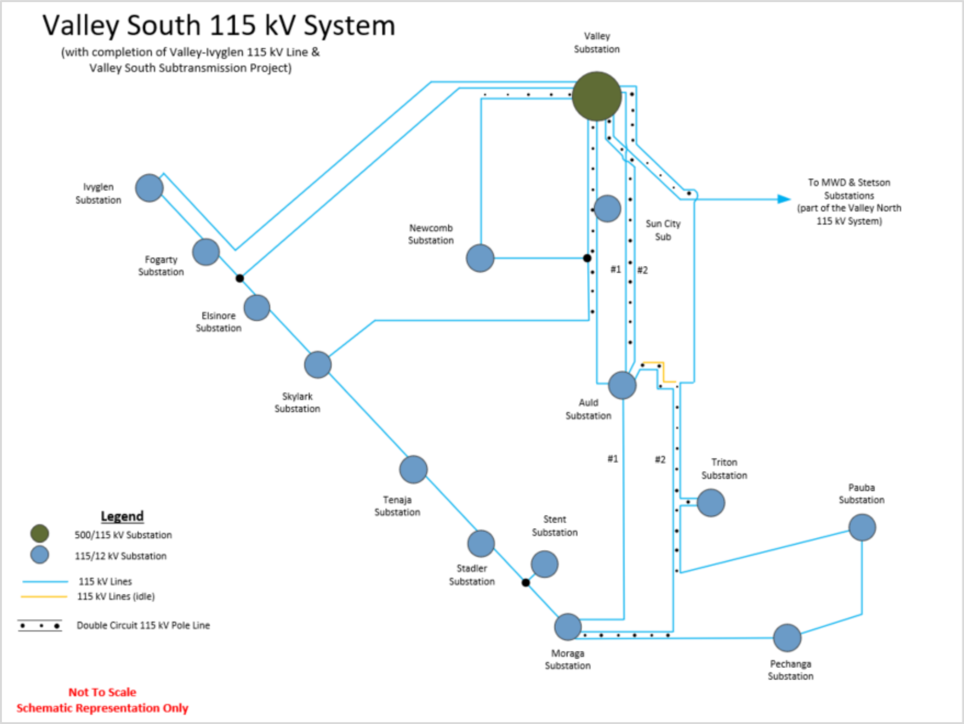


Figure 3-4. Valley South System Configuration (2021)

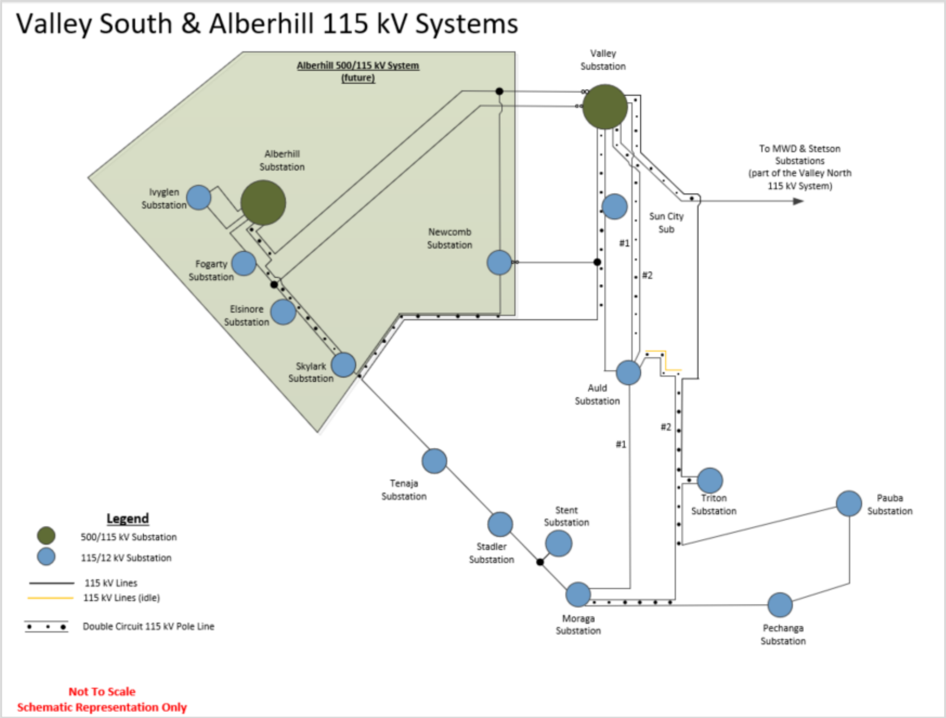


Figure 3-5. Valley South System Configuration (2022 with ASP in-service)

The load shape of the year 2016 was selected for this study. This selection was made because it demonstrated the largest variability among available records.[6] This load shape is presented in Figure 3-6.

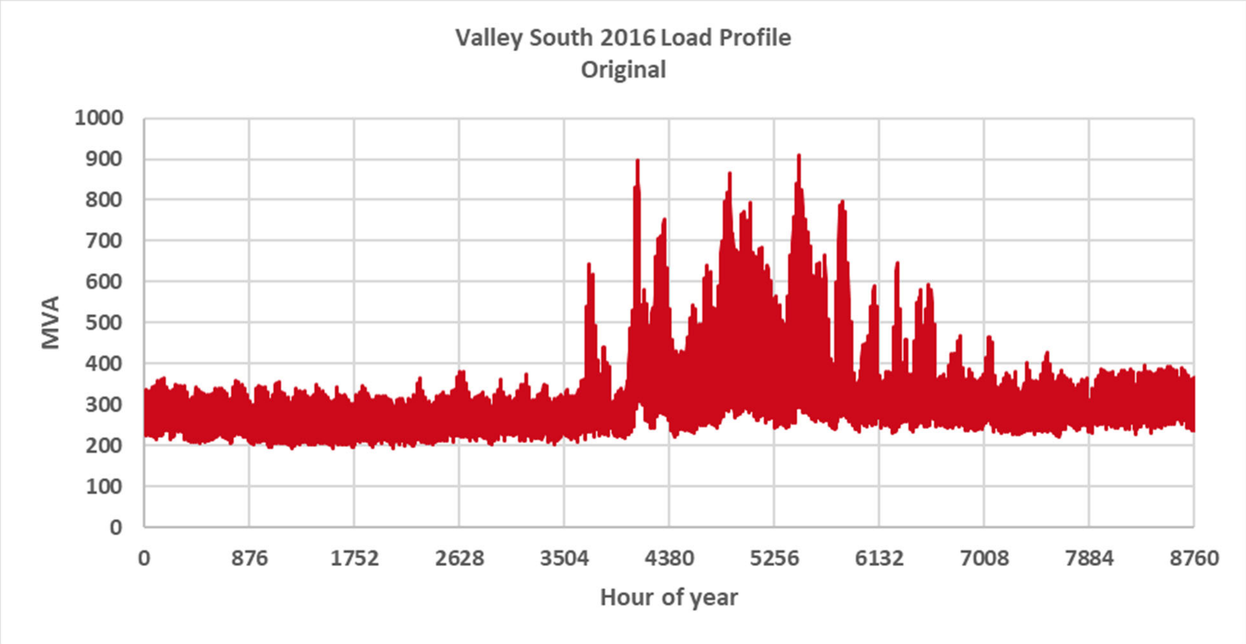


Figure 3-6. Load Shape of the Valley South System

3.2.2 Study Criteria

The following guidelines have been used through the course of this analysis to ensure consistency with SCE planning practices:

- The study and planning of projects adhered to SCE's Subtransmission Planning Criteria and Guidelines. Where applicable, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards were referenced when considering any potential impacts on the BES and the non-radial parts of the system under CAISO control.
- Transformer overload criteria established per SCE Subtransmission Planning Criteria and Guidelines for AA banks have been utilized.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.
- Voltage limits of 0.95–1.05 per unit under N-0 and N-1 operating configurations.
- Voltage deviation within established limits of ±5% post contingency.

3.2.3 Reliability Study Tools and Application

A combination of power flow simulation tools has been utilized for this analysis, such as General Electric's Positive Sequence Load Flow (PSLF) and PowerGem TARA. PSLF has been used for base-case model

[6] Note that the load shapes of years 2017 and 2018 were skewed due to the use of the AA-bank spare transformers as overload mitigation. Therefore, the load shape for year 2016 was adopted. Its shape is representative only and does not change among years.

development, conditioning, contingency development, and system diagram capabilities. TARA has been used to perform time-series power-flow analysis.

Time-series power-flow analysis is typically used in distribution system analysis to assess variation of quantities over time with changes in load, generation, power-line status, etc. It is now finding common application in transmission system analysis, especially when the system under study is not heavily meshed (radial in nature).

In this analysis, the peak load MVA of the load shape has been adjusted (scaled) to reflect the peak demand for each future year under study. This is represented by Figure 3-7 for the Valley South System as an example. The MVA peak load is then distributed amongst the various distribution substations in the Valley South System in proportion to their ratio of peak load to that of the entire Valley South System in the base case. Distribution substations under consideration in this analysis of the Valley South and Valley North Systems are listed in Table 3-1.

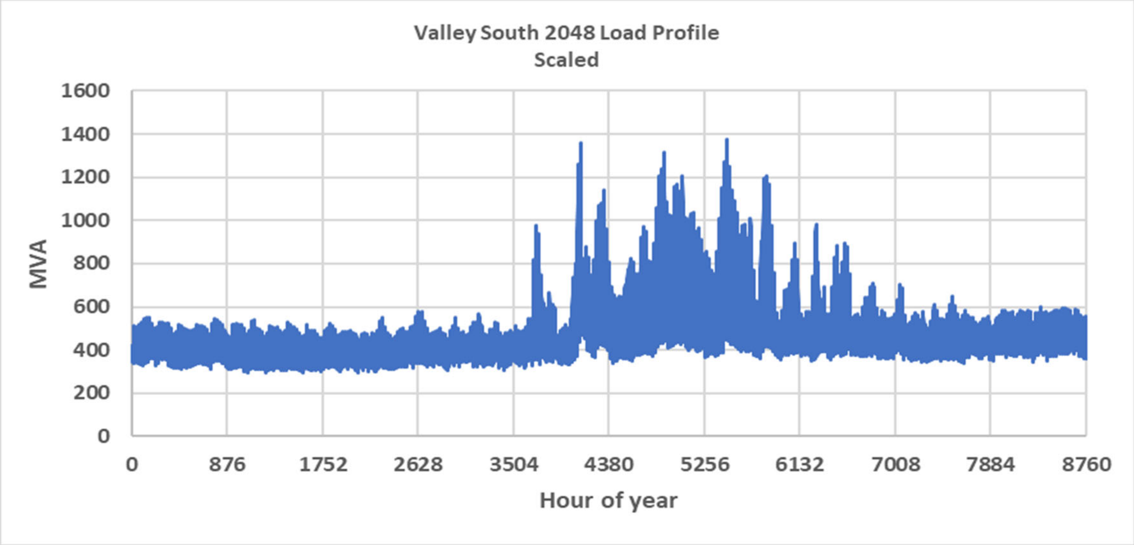


Figure 3-7. Scaled Valley South Load Shape Representative of Study Years

Table 3-1. Distribution Substation Load Buses

Valley South	Valley North
Auld	Alessandro
Elsinore	Bunker
Fogarty	Cajalco
Ivyglen	ESRP_MWD
Moraga	Karma
Newcomb	Lakeview
Pechanga	Mayberry

Valley South	Valley North
Pauba	Moreno
Skylark	Moval
Stadler	Nelson
Stent	Stetson
Sun City	
Tenaja	
Triton	

Hourly study (8,760 simulations per year) was conducted in selected years (5-year period) starting from the year 2022 or 2021 where transformer capacity need exceeds its operating limit. The results for the years in between were interpolated. At each simulation, the alternating current (AC) power-flow solution was solved, relevant equipment was monitored under N-0 conditions (using equipment ratings under normal conditions) and N-1 conditions (using equipment ratings under emergency conditions), potential reliability violations were recorded, and performance reliability metrics (as described in Section 3.2.4) were calculated. A flowchart of the overall study process is presented in Figure 3-8.

Unless otherwise specified, all calculations performed under reliability analysis compute the load at risk in MW or MWh, which is not a probability-weighted metric.

The N-1 contingency has been evaluated for every hour of the 8,760 simulations, and the outages were considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates single-circuit outages for all subtransmission lines within the system. Whenever an overload or voltage violation was observed, the binding constraint was applied to compute relevant reliability metric(s). When the project under evaluation has system tie-lines that can be leveraged, tie-lines were engaged to minimize system impacts. The losses are monitored every hour and aggregated across the existing and new transmission lines in the service area.

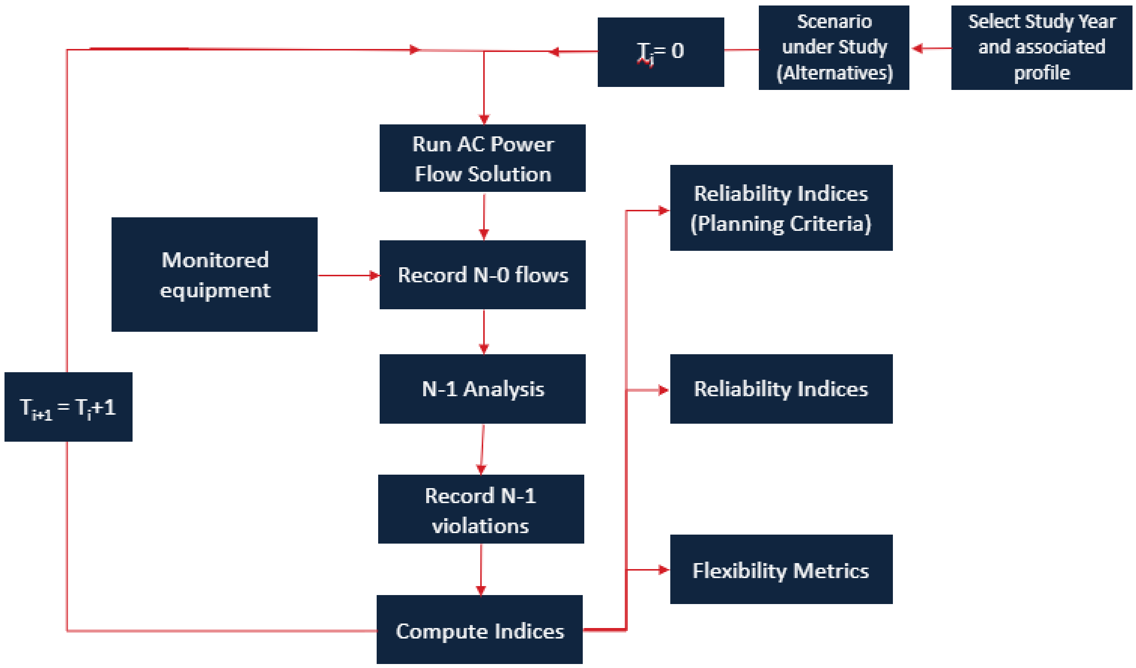


Figure 3-8. Flowchart of Reliability Assessment Process

Several operational flexibility metrics were developed to evaluate the incremental benefits of system tie-lines under emergency including planned and unplanned outages and HILP events in the Valley South System.

Flexibility Metric 1 evaluates the system under N-2 (common pole double-circuit outages) addressing combinations of two transmission lines out of service. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates double-circuit outages for all sub-transmission lines that share a common tower or right-of-way. The objective of this metric is to gauge the incremental benefits that projects provide for events that would traditionally result in unserved energy in the Valley South System. The flow chart in Figure 3-9 presents the overall process. The analysis is initiated taking into consideration the peak loading day (24-hour duration) for a year and applying the N-2 contingencies at each hour. Whenever an overload or voltage violation was observed, the binding constraint is used to determine the MWh load at risk (LAR) and to calculate the weighted amount using the associated contingency probabilities. The probability-weighted MWh is representative of the expected energy not served (EENS). The contingency probabilities were derived from a review of the historic outage data in the timeframe from 2005 to 2018 in the SCE system. The results for the peak day were compared against the baseline system and utilized as the common denominator to scale other days of the year for aggregation into the flexibility metric. During the analysis, it was observed that the system is vulnerable to N-2 events at load levels greater than 900 MW. This also corresponds to the Valley South operating limit wherein the spare transformer is switched into service to maintain transformer N-1 security. Thus, for purposes of scaling, only days with peak load greater than 900 MW were selected where there is a potential for LAR to accumulate in the system. When the project under evaluation has tie-lines, they are used to minimize system impacts.

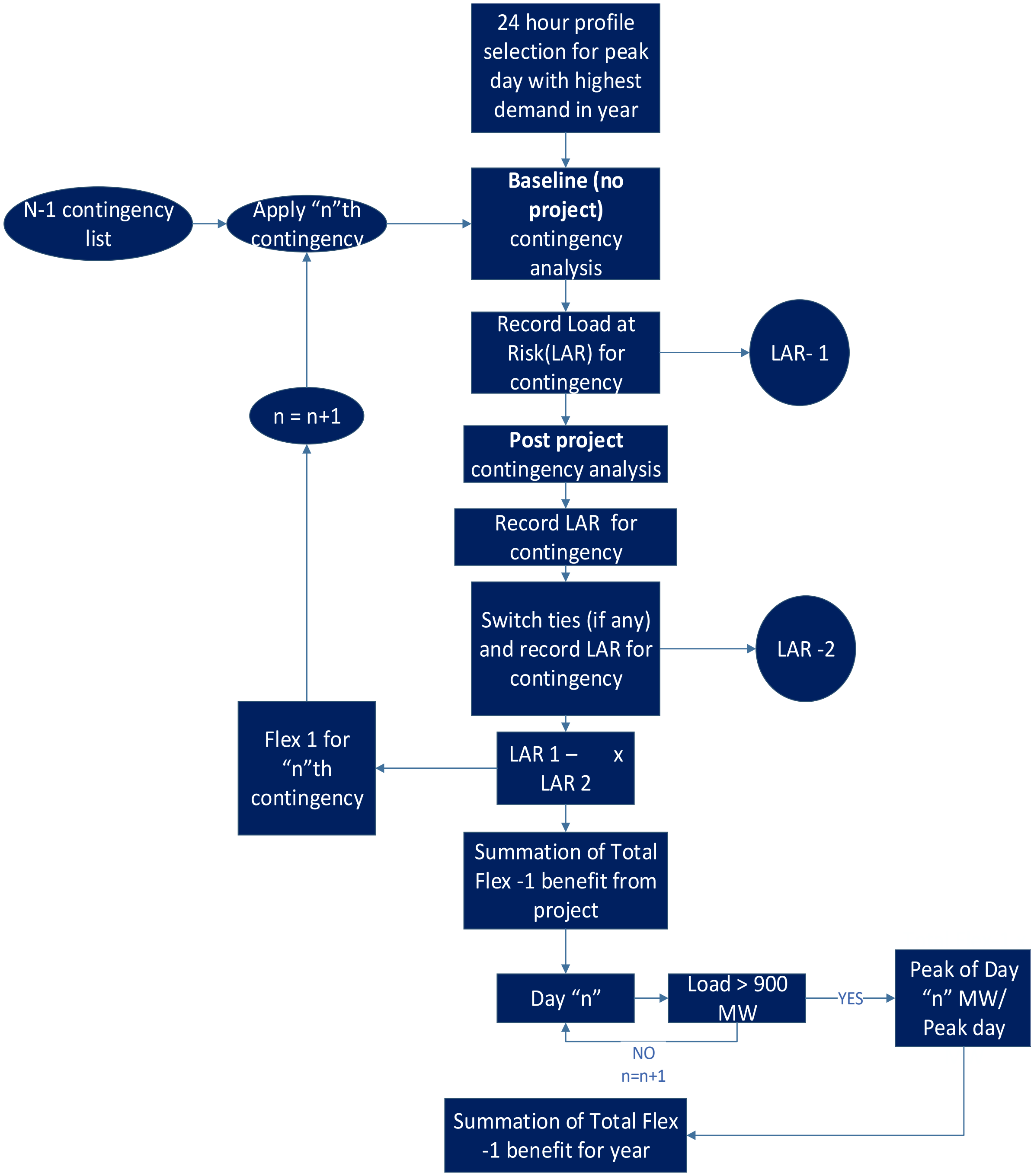


Figure 3-9. Flowchart of Flexibility Metric 1 (Flex-1) Calculation Process

Flexibility Metric 2 evaluates the project performance under HILP events in the Valley South System. This has been broken down into two components that consider different events impacting Valley South ENA. Both components utilize a combination of power flow and load profile analysis to determine the amount of LAR.

- Flexibility Metric 2-1 evaluates the impact of the entire Valley Substation out of service, wherein all the load served by Valley Substation is at risk. Considering a 2-week event (assumed substation outage duration to fully recover from an event of this magnitude), the average amount of LAR is determined. Utilizing power-flow simulations to evaluate the maximum load that can be transferred by projects using system ties, the amount of load that can be recovered is estimated.
- Flexibility Metric 2-2 evaluates a condition wherein the Valley South ENA is served by a single transformer (i.e., two load-serving transformers at Valley Substation are out of service). This scenario is a result of a catastrophic failure (e.g. fire or explosion) of one of the two transformers, and causing collateral damage to the adjacent transformer, rendering both transformers unavailable. Under these conditions, the spare transformer is used to serve a portion of the load. Utilizing the 8,760-load shape and the transformer short-term emergency loading limits (STELL) and long-term emergency loading limits (LTELL), the average amount of MWh over a 2-week duration LAR is estimated and aggregated ("mean time to repair" under major failures). The analysis accounts for the incremental relief offered by solutions with permanent and temporary load transfer using system ties.

3.2.4 Reliability Metrics

Prior to introducing reliability metrics, key elements of the overall project objectives must be outlined to provide direction and to guide further analysis. The following key concepts are revisited using applicable NERC guidelines and standards for the BES.

- Reliability has been measured with reference to equipment rating (thermal overload) and voltage magnitude (low voltages).
- Capacity represents the need to have adequate resources to ensure that the electricity demand can be met without service outages. Capacity is evaluated under normal and emergency system conditions and under normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address an emergency, maintenance, or planned outage condition. Therefore, it is expected to operate the system radially and to accommodate flexibility by employing normally open system tie-lines.
- Resilience has been viewed as an extension of the flexibility benefits, wherein system tie-lines are leveraged to recover load under HILP events.

Building on the overall project objectives, the following reliability metrics have been established to address the reliability, capacity, flexibility, and resilience needs of the system:

- **Load at Risk (LAR)**
  a. This is quantified by the amount of MWh at risk from each of the following elements:
     i. For each thermal overload, the MW amount to be curtailed to reduce loading below equipment ratings. This includes both transformers and power lines serving the Valley South system.
     ii. For voltage violations, the MW amount of load to be dropped based on the voltage sensitivity of the bus to bring the voltage to within established operating limits. The sensitivity study established ranges of load drop associated with varying levels of post-contingency voltage.

For deviations in a bus voltage from the 0.95 per unit limit, the amount of load drop to avoid the violation was determined.

b. LAR was computed for N-0 and N-1 events and aggregated or averaged over 1 year. The focus of the analysis is on the Valley South System. However, under N-0 condition, LAR recorded on the Valley North system was also accumulated during the simulation.
c. For N-1 events, system tie-lines are used where applicable to minimize the amount of MWh at risk.

- **Maximum Interrupted Power (IP)**
  a. This is quantified as the maximum amount of load in MW dropped to address thermal overloads and voltage violations. In other words, it is representative of the peak MW overload observed among all overloaded elements.
  b. IP was computed for N-0 events and N-1 events.

- **Valley South System Losses**: Losses (MWh) are treated as the active power losses in the Valley South System. New transmission lines, introduced by the scope of a project, have also been included in the loss computation.

- **Availability of Flexibility in the System**: Measure the availability of flexible resources (system tie-lines, switching schemes) to serve customer demand. It provides a proxy basis for the amount of flexibility (MWh) that an alternative project provides during maintenance operations, emergency events, or other operational issues. Two flexibility metrics are considered:
  a. Flexibility Metric 1: Capability to recover load during maintenance and outage conditions.
     i. Calculated as the amount of energy not served for N-2 events. The measure of the capability of the project to provide flexibility to avoid certain overloads and violations observable under the traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served using the flexibility attributes of the project.
  b. Flexibility Metric 2: Recover load for the emergency condition: Single point of failure at the Valley substation and its transformer banks.
     i. Flex-2-1: Calculated as the energy unserved when the system is impacted by HILP events such as loss of the Valley Substation resulting in no source left to serve the load. Projects that establish system tie-lines or connections to an adjacent network can support the recovery of load during these events. This metric is calculated over an average 2-week period (assumed minimum restoration duration for events of this magnitude) in the Valley South system.
     ii. Flex-2-2: Calculated as the amount of MWh load at risk when the system is operating with a single (spare) transformer at Valley Substation (two transformers are out of service due to major failures). This event is calculated over an average 2-week period in the Valley South System. Projects that establish system tie-lines to adjacent networks can support load recovery during these events.

- **Period of Flexibility Deficit (PFD)**: The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) was insufficient and resulted in energy not being served for a given time horizon.

The above list has been iteratively developed to successfully translate project objectives into quantifiable metrics and provides a basis for project performance evaluation.

3.3 Benefit-Cost Framework and Study Assumptions

Each of the projects has been evaluated using a benefit-cost framework that derives the value of project performance (and benefits) using a combination of methods. This framework provides an additional basis for the comparison of project performance while justifying the business case of each alternative to meet the load growth and reliability needs of the Valley South System.

The benefit is defined as the value of the impact of a project on a firm, a household, or society in general. This value can be either monetized or treated on a unit basis while dealing with reliability metrics like LAR, IP, and PFD (among other considerations). Net benefits are the total reductions in costs and damages as compared to the baseline, accruing to firms, customers, and society at large, excluding transfer payments between these beneficiary groups. All future benefits and costs are reduced to a net present worth using a discount rate and an inflation rate over the project lifetime or horizon of interest.

The overall process associated with the detailed alternatives analysis framework has been presented in Figure 3-10.

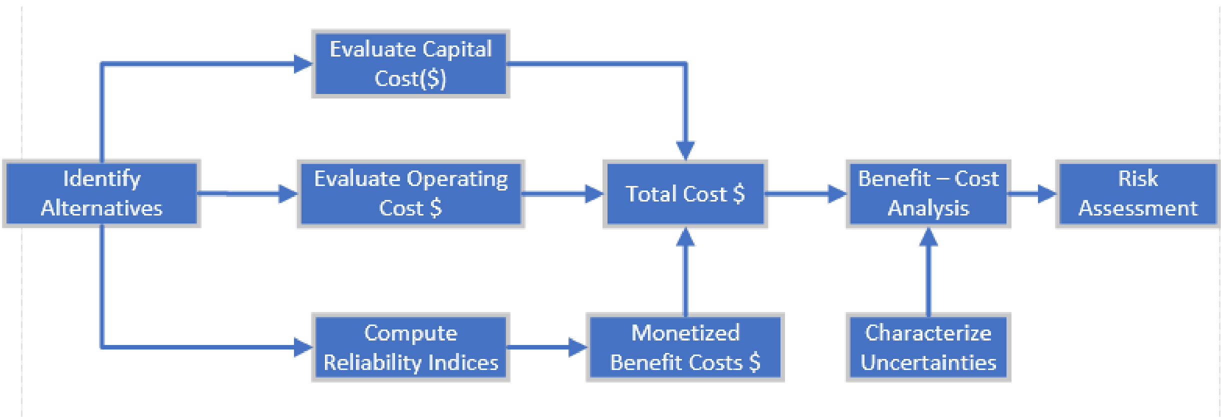


Figure 3-10. BCA Framework

The project costs have been developed by SCE as the present value of revenue requirements (PVRR) over the lifetime of the asset to include the rate of return on investment, initial capital investments, operations and maintenance (O&M), and equipment-specific costs. These are reflective of the direct costs used in the analysis. Due to the differences in equipment life of the projects under consideration, the present worth of costs has been used throughout the study horizon. The PVRR costs are offset for incremental revenues generated by the battery energy storage system (BESS) assets through market participation. Table 3-2 presents the financial assumptions considered in this analysis. Further details pertaining to each of the assumptions are presented in the upcoming sections of this report.

In the scope of this assessment, the benefits for considered metrics (Section 3.2.4) are derived by a comparison of system performance with and without the project in service. Depending on the benefit category, a distinction is made between monetized and non-monetized benefits. The monetized benefits are typically probability-weighted and represented as EENS. Unless otherwise specified, the non-monetized benefits are not probability weighted. The benefits in combination with PVRR costs have been used at different capacities to develop a comprehensive view of project performance. This evaluation framework includes a traditional benefit-cost comparison of alternatives to characterize the risks associated with load sensitivities.

Table 3-2. Financial and Operating Costs

Parameters	Value	Source
Discount rate (weighted aggregate cost of capital [WACC])	10%	SCE
Customer price (locational marginal price [LMP])	40 $/MWh	CAISO[7]
Inflation rate (price escalation)	2.5%	Quanta
Load distribution: residential	33%	SCE
Load distribution: small & medium business	36%	SCE
Load distribution: commercial and industrial	31%	SCE
Annual outage rate for Flexibility-2-2 events	0.0015	CIGRE[8]
Annual outage rate for HILP event (Flexibility-2-1 events)	0.01	NERC[9]

The non-monetized benefits have been presented in two different formats. From the perspective of reliability analysis (Sections 4 and 5), they are described as the sum (or the cumulative effect) of the benefits of the project over the project study horizon. In the cost-benefit framework (Section 6), the non-monetized benefits are calculated as the present worth of benefits discounted at the weighted aggregate cost of capital (WACC) throughout the study horizon. An example of the latter, LAR (MWh) benefits of the ASP under normal system condition (N-0) and their present worth using the discount rate of WACC are presented in Figure 3-11.

[7] http://oasis.caiso.com/ (Node: VALLEYSC_5_B1)
[8] Reference [8]
[9] Reference [7]

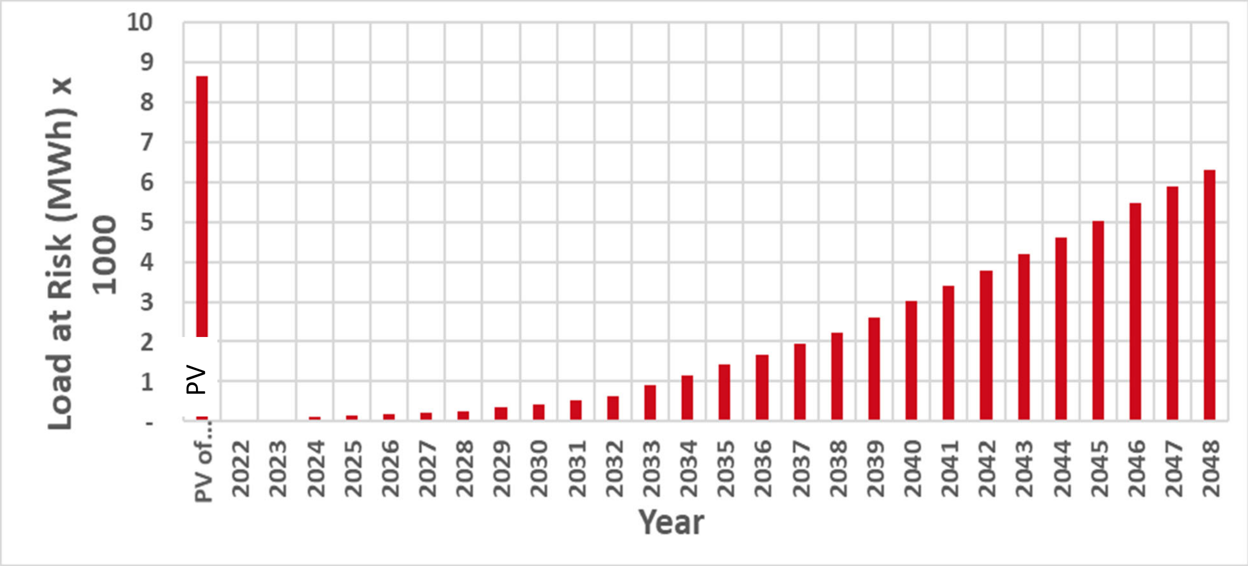


Figure 3-11. LAR (N-0) Benefits Accumulated for ASP over the Study Horizon

LAR (N-0, N-1) and flexibility indices (Flex-1, Flex-2-1, and Flex-2-2) were monetized using the $/kWh for unserved energy (load) from the customer perspective as provided by SCE [6]. These costs are separated into residential, small & medium business, and commercial & industrial in $/kWh. Figure 3-12 presents the costs over a 24-hour duration as applied to this assessment.

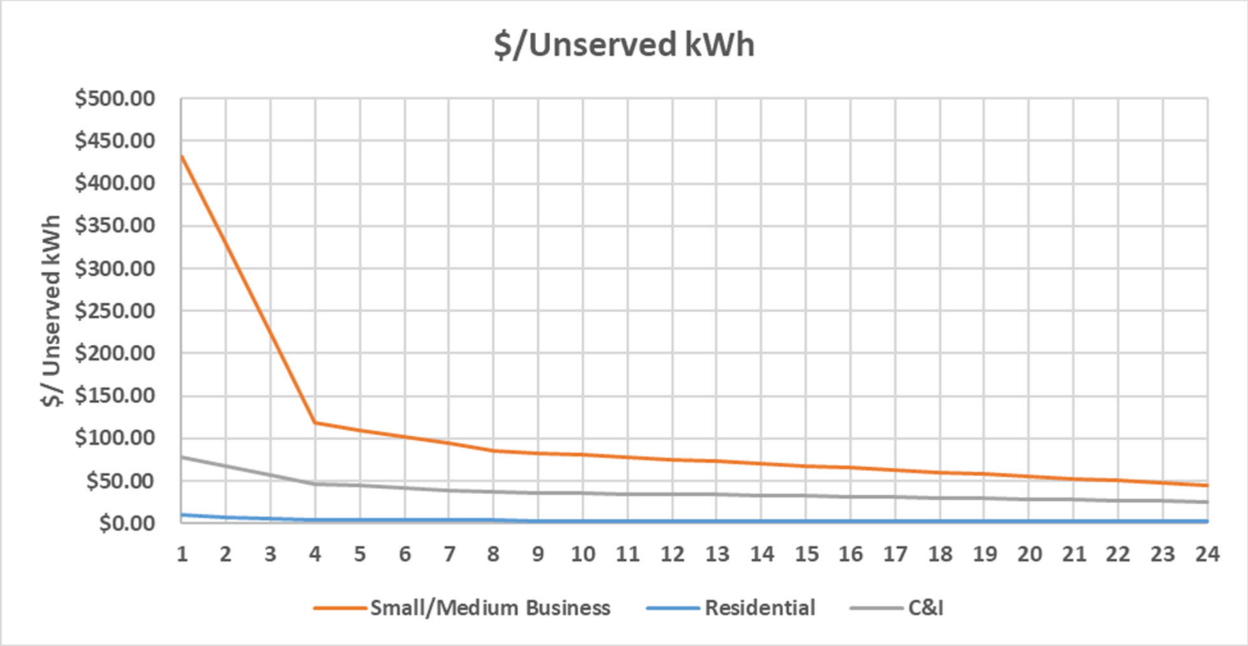


Figure 3-12. Value of Unserved kWh

The formulation below describes the monetized benefits and are complemented by the assumptions detailed previously in Table 3-2:

- EENS under N-0 conditions:
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour outage duration.
  - Costs derived from Figure 3-12 for the 1-hour outage, consistent with the principles of rolling outages between different customers each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
- EENS under N-1 conditions:
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) were used consistent with the principles of rolling outages between different customers each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities of circuit outages have been derived from historic event data in the Valley South, with a failure rate of 3.4 outages per 100 mile years and a mean duration of 2.8 hours.[10] The outage probabilities associated with N-1 circuits are presented in Table 3-3. For new lines in the alternatives, probabilities have been calculated using the estimated length of the circuit and the associated failure rates using the 3.4 outages per 100 mile-years metric.

Table 3-3. N-1 Line Outage Probabilities in Valley South

Line Name	Line Outage Probability Index
Auld-Moraga #1	0.36074
Auld-Moraga #2	0.40664
Auld-Sun City	0.27846
Elsinore-Skylark	0.1632
Fogarty-Ivyglen	0.32164
Moraga-Pechanga	0.17578
Moraga-Stadler-Stent	0.23188
Pauba-Pechanga	0.26112
Pauba-Triton	0.26622
Skylark-Tenaja	0.14994
Stadler-Tenaja	0.17374
Valley-Elsinore-Fogarty	0.59092

[10] Provided by SCE.

Line Name	Line Outage Probability Index
Valley-Newcomb	0.21454
Valley-Newcomb-Skylark	0.67966
Valley-Sun City	0.12818
Valley-Ivyglen	0.918
Valley-Auld #1	0.40664
Valley-Auld #2	0.34884
Valley-Triton	0.53244

- Flexibility-1 Metric
  - LAR (MWh) for 1 year multiplied by the cost of lost load ($/MWh) associated with a 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) are used consistent with the principles of rolling outages between different customers at each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities of circuit outages were derived from historic event data in Valley South System, with a failure rate of 0.8 outages per 100 mile years and a mean duration of 3 hours.
  - Considering the large combination of N-2 circuit outages that potentially impact the Valley South System, Flexibility 1 metrics are limited only to circuits that share a double circuit pole. The outage probabilities associated with N-2 contingencies are provided in the Appendix (Section 9).
- Flexibility-2-1 Metric
  - LAR (MWh) over an average 2-week duration multiplied by the cost of lost load ($/MWh) associated with assumed a 2-week outage duration multiplied by the outage probability.
  - The outage duration for this event is considered to be 2 weeks, reflective of the minimum restoration duration for an event of this magnitude. The cost has been derived as the average cost of lost load using hour 1 and hour 24 from Figure 3-12. Considering the uncertainties and shortage of publically available data sources to support the quantification of customer interruption costs due to events of this magnitude, the average of hour 1 and hour 24 cost data would prevent bias towards to a higher or lower monetary impact.
  - The cost associated with this event for residential is 5.68$/kWh, small/medium business is 238.4$/kWh, and commercial/industrial is 52.11$/kWh.
  - Probabilities associated with an event of this magnitude have been adopted as 0.01, signifying a 1-in-100 year event, adopted from NERC treatment of events of similar magnitude [7].
- Flexibility-2-2 Metric
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) were used consistent with the principles of rolling outages between different customers each hour.

  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities associated with this event have been adopted from the CIGRE Transformer Reliability Survey [8] data for major transformer events (fire or explosion) reported to be 0.00075 failures per transformer year.
- Losses
  - Losses (MWh) for the year multiplied by the average locational marginal price (LMP) at the Valley 500-kV substation.
  - The average LMPs are obtained from production simulation of the CAISO model for the year 2021 and 2022 and escalated each year.
  - The loss reduction is treated as a benefit and aggregated to the monetized EENS and Flex benefits.

3.3.1 Benefit-Cost Methodology

As described in earlier sections of this report, all costs and benefits have been evaluated over the study horizon from the in-service year 2021/2022 (depending on the need year from forecast used for the study) to 2048, which covers the 30-year horizon. The benefits associated with each project have been calculated as the present worth of each benefit category.

Following the quantification of the present worth of costs and benefits, three different types of analysis have been considered to select the most suitable project among the pool of alternatives. The proposed methodologies utilize the benefits in their non-monetized and monetized representation.

3.3.1.1 Benefit-Cost Analysis (BCA)

The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. However, it requires both benefits and costs to be treated on a common unit basis ($). Due to this, only monetized benefits are considered for this assessment. With the monetized benefits, a ratio is derived from the cost of the project to aggregate benefits introduced by the project.

The relevant benefit categories are monetized per the discussion in Section 3.3.1. The benefits are derived as differences in monetized costs with and without the project in service, which directly translates into cost savings from the customers' perspective. For example, without a project in service, customers in the Valley South system are vulnerable to 50 MWh of EENS in the year 2026 under normal system conditions (N-0), which translates into a $6.6M cost to customers. However, with a project such as ASP in service, the 50 MW of EENS is eliminated, and the $6.6M cost to customers will be avoided.

3.3.1.2 Levelized Cost Analysis

This evaluation is most suited for non-monetized metrics and their benefit evaluation. For each of the projects under consideration:

- The benefits have been quantified using the difference between the project and the baseline scenario.
- The benefits of each category from N-0 and N-1 are normalized as the ratio of $/unit benefit using their present worth over the horizon using the WACC discount rate.

- This index primarily provides insight into the investment value ($) from each project to achieve a unit of benefit improvement from baseline.

For example, the present worth of the ASP project cost is $474M, and the present worth of N-0 EENS benefit from the ASP (in comparison to baseline) is 8,657 MWh. The ratio of $474M/8,657 MWh suggests that this project would require an investment of $54,753 to achieve 1 MWh of N-0 EENS benefit.

3.3.1.3 Incremental BCA

Incremental BCA is used to rank and value the overall benefits attributed to an alternative project while providing an advantage to the most cost-effective solution that provides maximum benefit. The procedure is summarized below [9]:

Considering that the proposed project solutions are mutually exclusive alternatives (MEA), the MEAs are ranked based on their cost in increasing order. The do-nothing or least-cost MEA is selected as the baseline. The incremental benefit-to-cost ratio $\left(\frac{\Delta B}{\Delta C}\right)$ for the next least-expensive alternative is evaluated. Provided that the ratio is equal to or above unity, this alternative will be selected and replaces the baseline to evaluate the next least-expensive MEA. For a ratio below unity, the last baseline alternative is maintained. The incremental BCA will continue and iterate between the baseline and the next alternative. The selection will stop once the incremental benefit-to-cost ratio becomes unfavorable or the list is exhausted. The flowchart in Figure 3-13 provides an overview of the overall process.

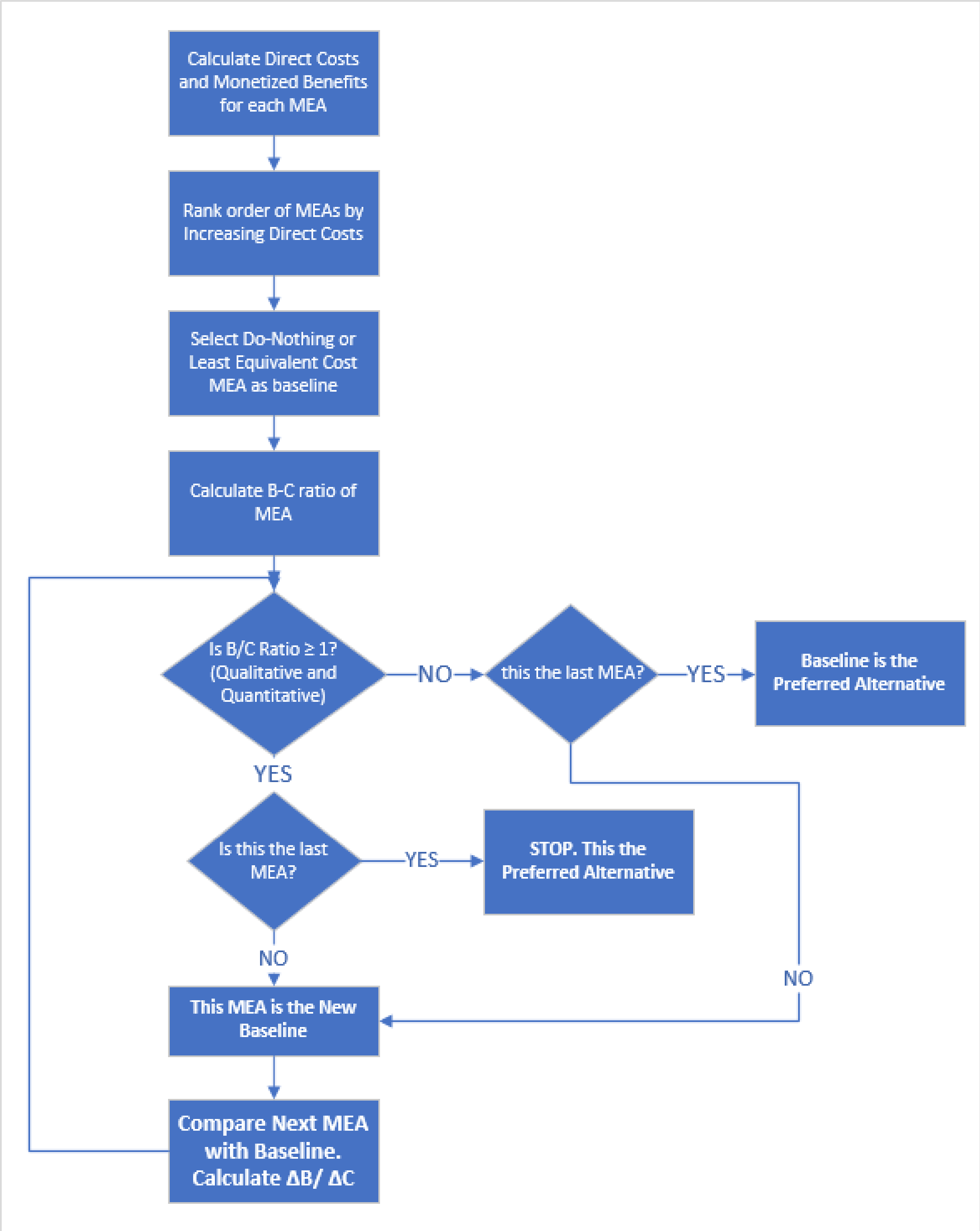


Figure 3-13. Incremental BCA Flowchart

Incremental BCA, also known as marginal benefit-to-cost analysis (MBCA), is considered a superior approach relative to a conventional BCA, for utilities to compare the cost effectiveness of alternative projects. The methodology assures "that dollars will be spent one at a time, with each dollar funding the project that will result in the most reliability benefit, resulting in an optimal budget allocation that identifies the projects that should be funded and the level of funding for each. This process allows service quality to remain as high as possible for a given level of funding—allowing electric utilities to be competitive, profitable, and successful in the new environment of deregulation" [10].

3.3.2 BESS Revenue Stacking

Revenue stacking describes a situation where a BESS is used for more than one domain of applications. When wholesale market applications and transmission and distribution (T&D) applications are allowed to be performed by the same BESS, the BESS accesses and participates in wholesale markets in addition to its primary function (T&D applications). T&D applications always take priority over wholesale market participation. This means, the function of the BESS always first ensures reliable operation of the T&D system as needed before consideration for market participation. Needed capacity and required dispatch levels must be considered as constraints to market participation.

In the Valley South planning area, batteries primarily provide local reliability, capacity, and flexibility benefits by supporting N-0, N-1, and N-2 needs in the system (primary application). To leverage the benefits from BESS-based solutions in each of these categories, the available capacity is reserved during summer months (peak demand period) from June to October (i.e., the BESS is only allowed to participate in the wholesale market outside the summer operating period).

When the BESS is not required for the primary application, it can time-shift the energy by participating in wholesale energy markets (i.e., market participation). This service results in ratepayer savings when the asset is assumed to be utility-owned with all energy cost savings passed on to ratepayers. "Shared application" or "hybrid application" is also investigated. This means that the storage is also used for ancillary services provision.

For applicable solutions that include BESS (NWAs or hybrid), additional potential benefits of BESS participating in CAISO wholesale and ancillary service (AS) markets are determined. The optimization uses the day-ahead (DA) prices for charging and discharging to simulate the strategy in which charging load and discharging are offered into the DA market. For this purpose, 2018–2019 DA for the node at the Valley South System is used. Energy storage also offers regulation-up (RegUp) and regulation-down (RegDown) services into the CAISO AS markets. Each day, the optimization would co-optimize the energy and AS participation across the day to maximize revenues subject to BESS operational constraints.

An energy credit is calculated under each scenario using the discharging revenues less the charging payments when only wholesale energy participation is considered. These energy credits in the wholesale and regulation cases also include an estimate of the settlement of regulation revenues at AS clearing prices. Generally, energy credits decrease as regulation capacity increases, as less battery capacity is then available for arbitrage. Table 3-4 summarizes data inputs that have been utilized for market analysis. This includes the data name, data type, and duration of the extracted data (applicable for time-series data).

Table 3-4. Data Inputs for Market Analysis

Input Name	Input Data Type (Source)	Value
Hourly Load Data (MW)	Time-series (SCE)	Data provided for 01/01/2016 – 01/01/2017
Load Threshold (MW)	Parameter (SCE)	1120 MW
Battery Variable O&M Cost ($/kWh)	Parameter (QTech)	0.005 $/kWh
Battery Min/Max Allowable State of Charge (SOC)	Parameter (QTech)	Min/Max: 5/100%
Start/End of Day SOC	Parameter (QTech)	50%
BESS Charging Efficiency	Parameter (QTech)	92%
Wholesale Day-Ahead LMP Data ($/kWh)	Time-series (ISO)	Data extracted for 01/01/2018 – 01/01/2019
BESS Discharging Efficiency	Parameter (QTech)	98%
Regulation Up and Down Clearing Market Prices ($/kW)	Time-series (ISO)	Data extracted for 01/01/18 – 01/01/2019
LMP Price Escalation/yr	Time-series (QTech)	2.5%
LA Basin Local RA Weighted Average Value ($/kW-Month)	Parameter (CPUC [11])	3.64/kW – Month for year 2018

This evaluation was carried out using a proprietary optimization tool developed by Quanta Technology. The tool uses a mixed-integer programming methodology. The co-optimization of storage resource participation in energy and AS markets is similar to that performed by the CAISO in its market-clearing. The tool computes the optimal allocation of BESS capacity to the different markets each hour while observing constraints imposed by the BESS characteristics and capabilities. This is done for the 8,760 hours of the year and the total revenues computed.

For the storage sizes established under each project, a bidding strategy of offering both charging and discharging into the DA markets was evaluated. As an additional step, the strategy of also offering RegUp and RegDown services into the CAISO AS markets was evaluated. Each day, the optimization would co-optimize the energy and AS participation across the day to maximize revenues subject to BESS operational constraints. The prices were escalated at 2.5%/yr to cover the horizon until 2048. Annual market benefits are calculated as a summation of energy, RegUp, and RegDown capacity less the variable O&M. Note: the variable O&M of $0.00579/kWh is considered for both charging and discharging of the battery. A low-order variable O&M cost is assumed to account for external costs including bidding, scheduling, metering, and settlement. Figure 3-14 exhibits a sample from the optimized BESS schedule over a 24-hour duration.

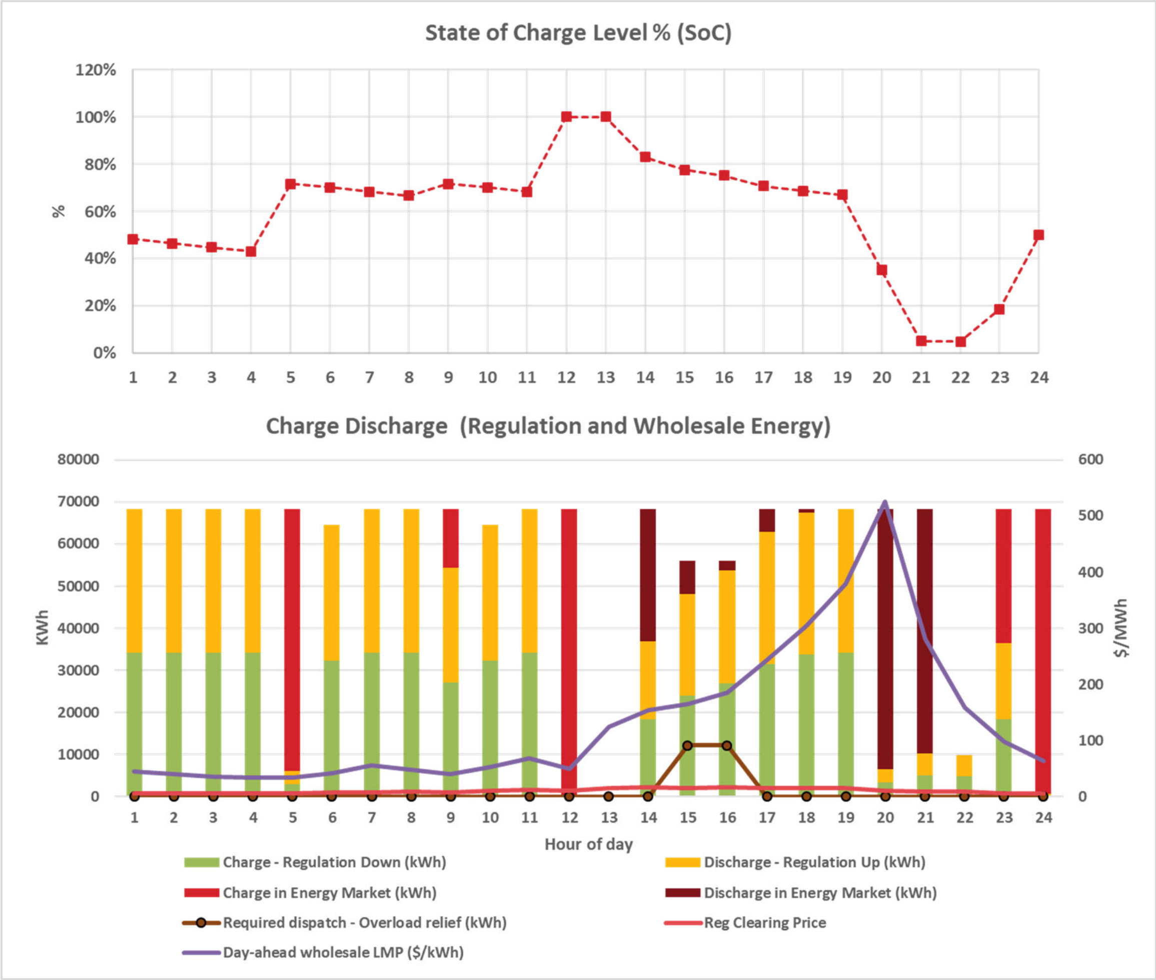


Figure 3-14. Daily Scheduling Example

In addition to participation in wholesale energy and AS markets, potential revenue available from the Resource Adequacy (RA capacity markets) have been estimated. The revenues are derived using local RA prices for the Los Angeles basin area obtained from the CPUC 2018 Resource Adequacy Report [11].

The model assumes available capacity is reserved during summer months (peak demand period) from June to October (i.e., the BESS is only allowed to participate in the RA market outside the summer operating period). The RA prices representative of the weighted average values has been used and escalated at a rate of 2.5% for future years. The analysis takes into consideration the minimum 4-hour duration requirement for BESS participation while accounting for capacity fading at a rate of 3% per year.

3.3.3 Risk Assessment

Load forecast uncertainty has been treated in the risk assessment. The range of load variability associated with the three main forecasts considered in this study are presented in Figure 3-15 and Table 3-5.

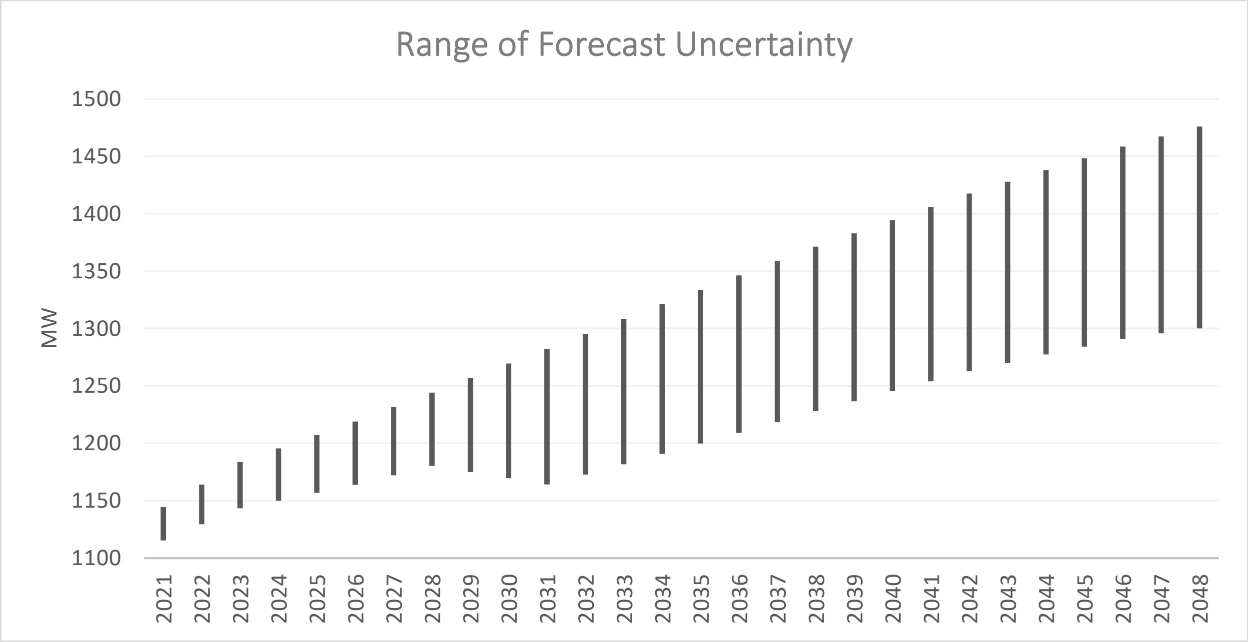


Figure 3-15. Load Forecast Range

Table 3-5. Statistics Associated with Load Forecast

Year	Low (MW)	High (MW)
2023	1146	1181
2028	1183	1242
2038	1230	1369
2048	1302	1474

Considering the spectrum of alternative projects under analysis, a deterministic risk analysis has been performed. The deterministic risk analysis provides insight into the capabilities of alternatives to meet the incremental demands of the system in the future and characterizes the risks associated with load sensitivities. Within the scope of the deterministic risk analysis, the performance of project alternatives is investigated under various forecast trends and compared using benefit-cost metrics.

4 RELIABILITY ASSESSMENT OF ALBERHILL SYSTEM PROJECT

4.1 Introduction

The objective of the analysis in this section is to apply the reliability assessment framework to the ASP. The performance and benefits of the ASP are computed in comparison to the baseline scenario (i.e., no project in service) following the methodology detailed in Section 3.2. The performance of the baseline system is initially presented, followed by the ASP for all considered load forecasts (PVWatts, Effective PV, and Spatial Base).

In order to successfully evaluate the benefits of potential projects in the Valley South System, the performance of each project must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance
2. To compare project performance to the baseline scenario (no project in service)
3. To establish a basis to value the performance of the ASP against overall project objectives
4. To take into consideration the benefits or impacts of flexibility and resilience (HILP events)
5. To guide for comparing projects against alternatives

Within the framework of this analysis, the reliability, capacity, flexibility, and resilience benefits have been quantified.

4.2 Reliability Analysis of the Baseline System

The baseline system is the no-project scenario within this analysis. It depicts a condition wherein the load grows to levels established by the forecast under the study, without any project in service to address the shortfalls in transformer capacity. This scenario forms the primary basis for comparison against alternatives performance to evaluate the benefits associated with the project.

The baseline system has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

4.2.1 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions in the system are presented in Table 4-1 for the Effective PV Forecast, Table 4-2 for the Spatial Base Forecast, and Table 4 -3 for the PVWatts Forecast.

Table 4-1. Baseline N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	22	13	2	49,667
2028	250	65	7	52,288
2033	905	120	18	54,472
2038	2,212	190	37	56,656
2043	4,184	246	53	58,840
2048	6,310	288	77	61,024

Table 4-2. Baseline N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	50	22	4	50,082
2022	129	42	5	50,888
2028	908	131	19	54,467
2033	2,844	205	42	57,450
2038	5,741	280	69	60,432
2043	9,888	348	102	63,415
2048	14,522	411	142	66,397

Table 4-3. Baseline N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	22	13	2	49,667
2028	250	65	7	52,288
2033	292	67	8	52,859
2038	740	117	14	54,310
2043	1,504	155	26	55,761
2048	2,659	199	37	57,211

4.2.2 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 4-4 for the Effective PV Forecast, Table 4-5 for the Spatial Base Forecast, and Table 4-6 for the PVWatts Forecast.

Table 4-4. Baseline N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	10	2	14	54,545	127,935	2,138
2028	67	11	32	163,415	133,688	2,774
2033	249	21	54	254,140	139,702	3,514
2038	679	35	88	344,864	145,991	4,421
2043	1,596	45	120	435,589	151,619	5,294
2048	2,823	68	153	526,314	155,733	5,975

Table 4-5. Baseline N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	18	4	18	54,545	129,095	2,255
2022	40	6	28	87,602	131,322	2,491
2028	231	23	60	285,950	140,388	3,612
2033	989	40	98	451,239	147,622	4,670
2038	2,435	62	147	616,529	154,744	5,811
2043	5,599	71	204	781,818	161,142	6,952
2048	10,024	128	261	947,107	166,580	8,000

Table 4-6. Baseline N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	10	2	14	54,545	127,935	2,138
2028	67	11	32	122,681	133,688	2,774
2033	75	11	33	531,497	133,840	2,791
2038	182	20	51	872,176	139,065	3,432
2043	454	29	79	1,212,856	143,845	4,110
2048	805	35	94	1,553,536	147,226	4,615

In the baseline system analysis, the following constraints (Table 4-7) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 4-7, only thermal violations associated with each constraint are reported.

Table 4-7. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	Base case	2021	2022	2022
Auld to Moraga #1	N-0	Base case	2038	2047	
Valley EFG to Tap 39	N-0	Base case	2043		
Valley EFG to Sun City	N-0	Base case	2043		
Auld-Moraga #2	N-1	Auld-Moraga #1	2032	2038	2048
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG -Newcomb-Skylark	2033	2043	
Tap 39-Elsinore	N-1	Valley EFG -Newcomb-Skylark	2028	2038	2043
Auld-Moraga #1	N-1	Skylark-Tenaja	2038	2048	
Valley EFG-Sun City	N-1	Skylark-Tenaja	2048		
Moraga-Tap 150	N-1	Skylark-Tenaja	2048		
Skylark-Tap 22	N-1	Valley EFG -Elsinore-Fogarty	2028	2033	2038
Valley EFG-Sun City	N-1	Valley EFG -Auld #1	2038	2043	
Valley EFG-Auld #2	N-1	Valley EFG -Auld #1	2048		
Valley EFG-Auld #1	N-1	Valley EFG -Sun City	2038	2048	
Valley EFG-Auld #2	N-1	Valley EFG -Sun City	2043		
Valley EFG-Tap 22	N-1	Valley EFG -Newcomb	2038	2043	
Valley EFG-Auld #1	N-1	Valley EFG -Auld #2	2038	2048	
Valley EFG-Sun City	N-1	Valley EFG-Auld #2	2038	2043	
Valley EFG-Triton	N-1	Moraga-Pechanga	2043	-	
Valley EFG-Tap 39	N-1	Valley EFG -Ivyglen	2048	-	
Auld-Moraga #1	N-1	Valley EFG-Triton	2032	2043	2048
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2038	2043
Valley EFG-Auld #1	N-1	Valley EFG-Triton	2048		
Valley EFG-Sun City	N-1	Valley EFG-Triton	2043		

4.2.3 Key Highlights of System Performance

The key highlights of system performance for the baseline system are as follows:

1. Without any project in service, the Valley South System transformers are projected to overload in the year 2022. Sensitivity scenario using Spatial Base forecast demonstrates a need year by 2021.
2. In the Effective PV forecast by the year 2028, 250 MWh of LAR is observed in the system under N-0 conditions. This extends to 6,309 MWh by 2048 with no project in service. Through the range of forecast sensitivities, the potential LAR ranges from 2,600 MWh to 14,500 MWh in a 30-year horizon.
3. In the Effective PV forecast between 2028 and 2048, the flexibility deficit in the system increases from 7 hours to 77 hours under the N-0 condition. Considering the range of forecast uncertainties, the number of hours of deficit in the system under N-0 range from 37 hours to 147 hours in the year 2048.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasingly challenging to maintain system N-1 security.
5. In the Effective PV forecast by the year 2028, 67 MWh of LAR is observable in the system under N-1 conditions. This extends to 2,800 MWh by 2048 with no project in service. Through the range of forecast sensitivities, the potential LAR ranges from 805 MWh to 10,000 MWh in a 30-year horizon.

4.3 Reliability Analysis of the Alberhill System Project (Project A)

The ASP has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

4.3.1 Description of Project Solution

The ASP would be constructed in Riverside County and includes the following components:

1. Construction of a new 1,120 MVA 500/115 kV substation to increase the electrical service capacity to the area currently served by the Valley South 115 kV system. Two transformers were installed, one of which is a spare.
2. Construction of two new 500 kV transmission line segments to connect the new substation to SCE's existing Serrano–Valley 500 kV transmission line.
3. Construction of new 115 kV subtransmission lines and modifications to existing 115 kV subtransmission lines to transfer five existing 115/12 kV distribution substations (Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb) currently served by the Valley South 115 kV System to the Alberhill 115 kV system.
4. Installation of telecommunications improvements to connect the new facilities to SCE's telecommunications network.

Figure 4-1 presents an overview of the project layout and schematic.

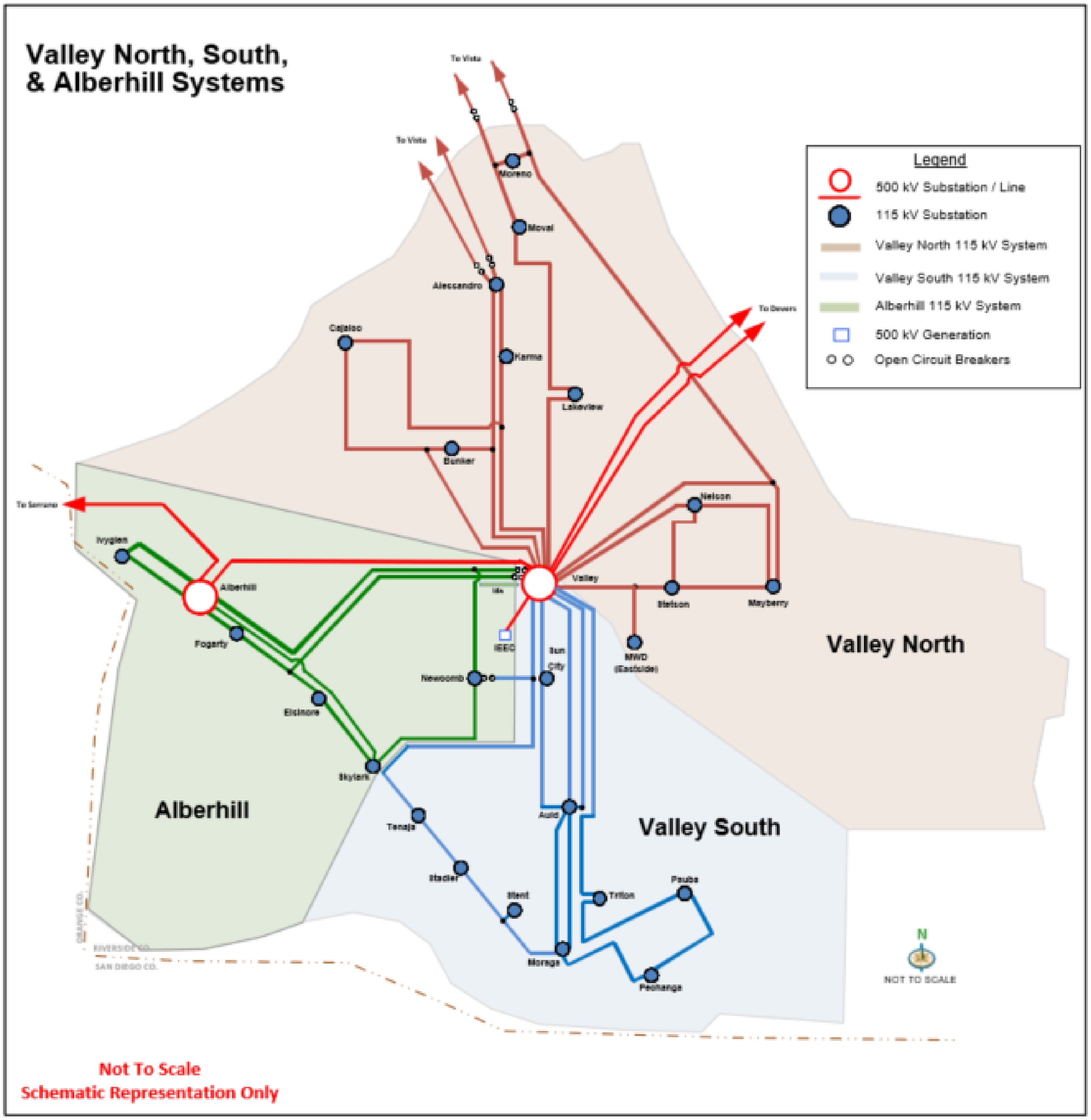


Figure 4-1. Alberhill System Project and Resulting Valley North and South Systems

4.3.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 4-8 for the Effective PV Forecast, Table 4-9 for the Spatial Base Forecast, and Table 4-10 for the PVWatts Forecast.

Table 4-8. Alberhill N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	40,621
2028	0	0	0	42,671
2033	0	0	0	44,380
2038	0	0	0	46,089
2043	0	0	0	47,797
2048	3	2	2	49,506

Table 4-9. Alberhill N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	40,954
2022	0	0	0	41,590
2028	0	0	0	43,417
2033	0	0	0	44,939
2038	1	1	1	46,462
2043	28	8	6	47,984
2048	93	14	10	49,506

Table 4-10. Alberhill N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	40,621
2028	0	0	0	42,671
2033	0	0	0	42,310
2038	0	0	0	43,725
2043	0	0	0	45,140
2048	0	0	0	46,555

4.3.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 4-11 for the Effective PV Forecast, Table 4-12 for the Spatial Base Forecast, and Table 4-13 for the PVWatts Forecast.

Table 4-11. Alberhill N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	0	1163	0
2028	0	0	0	30,438	1516	0
2033	0	0	0	56,720	1947	0
2038	21	8	4	83,001	2452	0
2043	84	17	8	109,283	2954	1
2048	202	24	14	136,664	3345	4

Table 4-12. Alberhill N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	0	1,229	-
2022	0	0	0	11,530	1,363	-
2028	0	0	0	80,713	1,999	-
2033	33	11	5	138,365	2,593	-
2038	163	22	12	196,017	3,249	3
2043	530	34	6	253,669	3,896	11
2048	1,080	43	43	311,321	4,494	27

Table 4-13. Alberhill N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	0	1,163	0
2028	0	0	0	11,254	1,516	0
2033	0	0	0	20,632	1,526	0
2038	0	0	0	30,011	1,899	0
2043	7	4	2	39,389	2,272	0
2048	30	10	5	48,395	2,559	0

In analyzing the ASP, the following constraints (Table 4-14) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 4-14, only thermal violations associated with each constraint are reported.

Table 4-14. List of ASP Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Alberhill-Fogarty	N-0	N/A (base case)	2038	2046	-
Auld – Moraga #1	N-0	N/A (base case)	2048		
Valley EFG – Sun City	N-0	N/A (base case)	2048		
Alberhill-Fogarty	N-1	Alberhill-Skylark	2033	2038	2043
Alberhill-Skylark	N-1	Alberhill–Fogarty	2038	2043	-
Auld-Moraga #1	N-1	Valley EFG-Newcomb-Tenaja	2038	2048	-
Alberhill-Fogarty	N-1	Alberhill-Newcomb-Valley EFG	2048	-	-

4.3.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the ASP to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 4-15 for the three forecasts.

Table 4-15. Cumulative Benefits – Alberhill System Project

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	275,699	277,608	362,676
N-1	LAR (MWh)	6,282	20,327	69,479
N-1	IP (MW)	428	601	954
N-1	PFD (hr)	1,300	1,907	3,277
N-1	Flex-1 LAR (MWh)	3,901,429	6,024,126	9,664,642
N-1	Flex-2-1 LAR (MWh)	3,657,700	3,779,849	4,101,527
N-1	Flex-2-2 LAR (MWh)	87,801	106,937	141,992

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	LAR (MWh)	22,751	56,575	140,566
N-0	IP (MW)	2,713	4,053	6,213
N-0	PFD (hr)	411	811	1,559

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the ASP. The robustness of the project is justified through benefits accrued across all forecast sensitivities. The results for each category of benefits demonstrate the merits of the ASP to complement the increasing reliability, capacity, flexibility, and resilience needs in the Valley South service area.

4.3.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the ASP in service, overloading on the Valley South System transformers is avoided over the study horizon. This trend is observable across all considered forecasts. 3 MWh of LAR is recorded under N-0 condition (Effective PV Forecast) in the year 2048 due to an observed overload of the Alberhill–Fogarty 115 kV line. Across all sensitivities, the benefits range between 22.7 and 140.5 GWh of avoided LAR.
2. Considerable reduction in N-1 overloads is observed in the near-term and long-term horizons for all forecasts. With the ASP in service, the N-1 benefits in the system range from 6.2 to 66.7 GWh through all forecasts. In the Effective PV Forecast by the year 2038, overloads due to N-1 events are observed on the Alberhill–Fogarty 115 kV line, the Alberhill–Skylark 115 kV line, and the Auld–Moraga 115 kV line.
3. The project provides significant flexibility to address planned, unplanned, or emergency outages throughout the system while also providing significant benefits to address needs under HILP events that occur in the Valley South System. The ASP addresses the full range of flexibility needs identified by the baseline system across all forecast sensitivities.
4. Following a HILP event, the ASP can recover approximately 400 MW of load in Valley South leveraging capabilities of its system tie-lines.
5. Overall, the ASP demonstrated robustness to address the needs identified in the Valley South System service territory. The project design offers several advantages that can also overcome the variability and uncertainty associated with the load forecast. The available flexibility through system tie-lines provides relief to system operations under N-1, N-2, and HILP events that affect the region.

5 SCREENING AND RELIABILITY ASSESSMENT OF ALTERNATIVES

5.1 Introduction

The objective of this analysis is to identify and screen potential alternatives that meet the project objectives detailed in Section 1.2. Each of these alternatives is evaluated using the criteria established in Section 3.2.4.

The considered alternatives are evaluated for their capability to address system capacity and reliability needs. The alternatives are categorized as Minimal Investment Alternatives, Conventional, Non-Wire Alternatives (NWA), and Hybrid solutions.

Minimal Investment Alternatives can also be referred to as a "do nothing" scenario in which no large project is implemented to address the needs of the system. These include spare equipment investments, re-rating or equipment upgrades, component hardening, vegetation management, undergrounding T&D, reinforcement of poles and towers, and emergency operations like load shedding relays. Conventional solutions include alternative substation or transmission line configurations. NWAs include energy storage, demand response, energy efficiency programs, DERs, and other smart grid investments like smart meters. Hybrid solutions are a combination of Conventional and NWAs.

The solution alternatives are organized into four primary categories, as outlined in Figure 5-1.

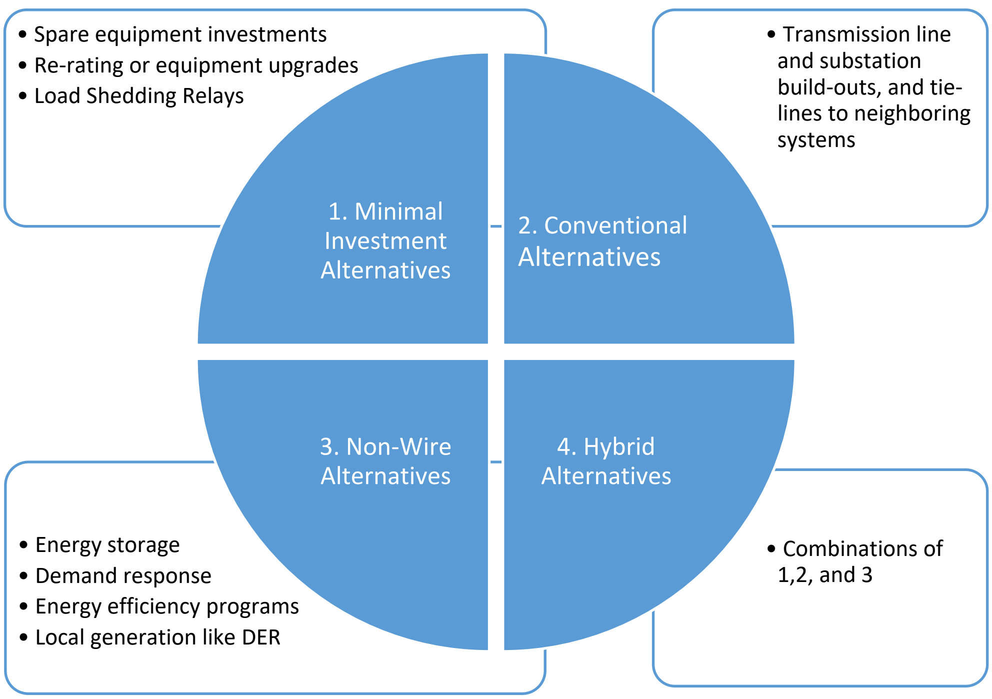


Figure 5-1. Categorization of Considered Alternatives

The highlights of the procedure used to identify potential alternative projects are as follows:

- Use reliability analysis results with no project in service and available reports detailing the layout of the Valley South System to establish Minimum Investment Alternatives to mitigate and meet the objectives.
- An exhaustive search (brute force) approach was used to establish system tie-lines between the Valley South System and neighboring systems. Tie-lines performance was evaluated under the most constraining conditions identified from the "no project" scenario results. Figure 5-2 describes the Valley South System relative to neighboring electrical systems.
- Seek guidance from the LAR metrics to provide the viability of alternatives. For example, the identified MWh need is large and predominantly occurs during off-peak hours of the day when PV-DER type solutions might not be available.

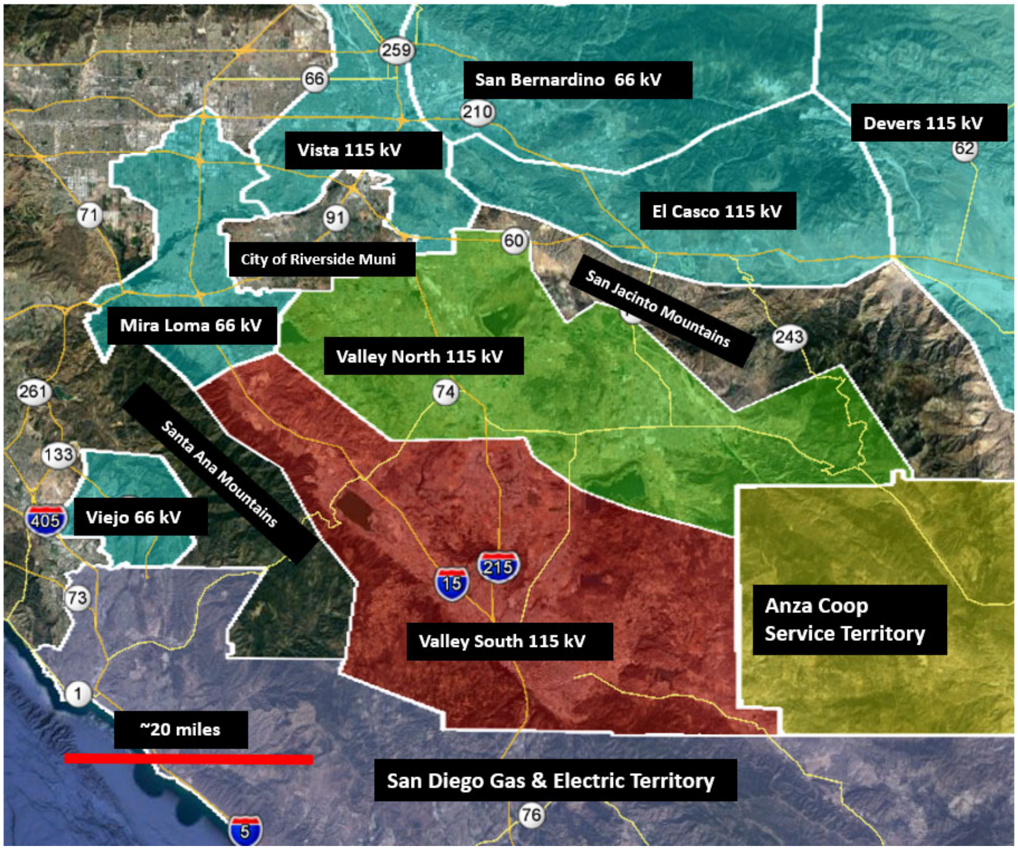


Figure 5-2. Valley System and Neighboring Electrical Systems

5.2 Project Screening and Selection

The initial screening process resulted in a total of 17 alternatives. These included all categories of options outlined in Figure 5-1. The 17 alternatives were preliminarily screened through a fatal flaw analysis driven by the overall project objectives. Through this process, four alternatives were dropped from further consideration. The dropped alternatives included 1) utilization of spare transformer for the Valley South System, 2) upgrading transformer ratings, 3) investing in load shedding relays, and 4) installation of two additional 500/115kV transformer banks. Upon further inspection and analysis, these four alternatives were determined to not satisfy all project objective needs or were not feasible from an implementation or constructability perspective.

The final list of 13 alternatives included a combination of conventional, non-wire, and hybrid solutions. These alternatives are presented below. Further details pertaining to the scope, design, and project performance are described in the upcoming sections. Note that the ASP and project alternatives are identified using an alphabetic character, A through M, which is used throughout this report to refer to each alternative.

<u>Conventional Alternatives</u>

The considered conventional transmission alternatives are detailed below.

A. Alberhill System Project
B. San Diego Gas & Electric Project
C. SCE Orange County Project
D. Menifee Project
E. Mira Loma Project
F. Valley South to Valley North Project
G. Valley South to Valley North to Vista Project

<u>Non-Wire Alternatives</u>

The following non-wire alternatives have been considered:

H. Centralized BESS in Valley South Project

<u>Hybrid Solutions</u>

The following hybrid solutions that involve a combination of conventional and hybrid solutions have been considered in this analysis:

I. Valley South to Valley North and Distributed BESS in Valley South Project
J. San Diego Gas & Electric and Centralized BESS in Valley South (Alternatives B + H)
K. Mira Loma and Centralized BESS in Valley South (Alternatives E + H)
L. Valley South to Valley North and Centralized BESS in Valley South and Valley North (Alternatives F + H)
M. Valley South to Valley North to Vista and Centralized BESS in Valley South (Alternatives G + H)

5.3 Detailed Project Analysis

In the detailed project analysis, the reliability assessment framework was applied to all 13 considered alternatives. The performance and benefits of each alternative were computed in comparison to the baseline scenario (i.e., no project in service) following the methodology detailed in Section 3.2. The results of the baseline scenario are presented in Section 4.2 and the ASP (Alternative A) in Section 4.3. The performance of each alternative is presented for the range of load forecast sensitivities (PVWatts, Effective PV, and Spatial Base).

5.3.1 San Diego Gas & Electric (Project B)

The original premise for this project is to construct a new 230/115 kV substation that provides power via the San Diego Gas & Electric system and to transfer some of SCE's distribution substations to this new 230/115 kV system. This project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.1.1 Description of Project Solution

The proposed project would transfer SCE's Pechanga and Pauba 115/12 kV distribution substations to a new 230/115 kV transmission substation provided service from the SDG&E electric system. The proposed project would include the following components:

1. The point of interconnection would be a new 230/115 kV substation between the SCE-owned Pechanga Substation and SDG&E-owned Talega-Escondido 230 kV transmission line to the south. Two 230/115 kV transformers (one load-serving and one spare).
2. New double-circuit 230 kV transmission line looping the new substation into SDG&E's Talega-Escondido 230 kV transmission line.
3. New 115 kV line construction to allow the transfer of Pechanga and Pauba Substations from Valley South to new 230/115 kV substation.
4. Create system tie-lines between the new 230/115 kV system and the Valley South System through normally-open circuit breakers at SCE's Triton and Moraga Substations to provide operational flexibility and to accommodate potential future additional load transfers.
5. Rebuild of existing Pechanga Substation and/or expansion of existing property at Pechanga Substation to accommodate required new 115 kV switch rack positions.

Figure 5-3 presents a high-level representation of the proposed configuration.

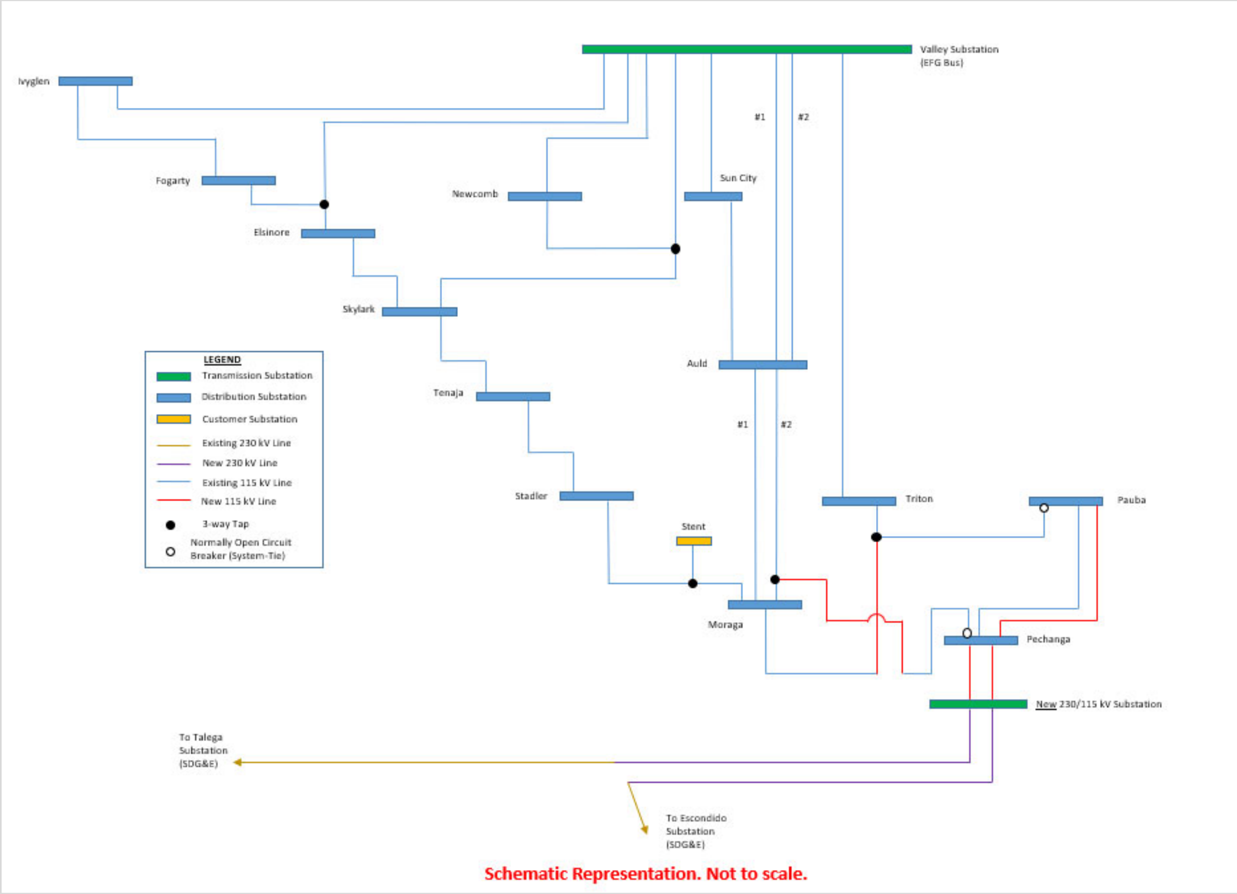


Figure 5-3. SDG&E Project Scope

5.3.1.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-1 for the Effective PV Forecast, Table 5-2 for the Spatial Base Forecast, and Table 5-3 for the PVWatts Forecast.

Table 5-1. SDG&E N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	48,529
2038	0	0	0	50,505
2043	82	31	4	52,481
2048	244	63	7	54,457

Table 5-2. SDG&E N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	44,182
2022	0	0	0	44,715
2028	0	0	0	46,963
2033	0	0	0	48,837
2038	199	56	6	50,710
2043	655	112	12	52,584
2048	1,499	152	28	54,457

Table 5-3. SDG&E N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	45,310
2038	0	0	0	46,470
2043	0	0	0	47,630
2048	3	3	1	48,791

5.3.1.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-4 for the Effective PV Forecast, Table 5-5 for the Spatial Base Forecast, and Table 5-6 for the PVWatts Forecast.

Table 5-4. SDG&E N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	20,830	15,152	428
2028	0	0	0	52,762	17,895	636
2033	0	0	0	79,372	21,123	926
2038	0	0	0	105,982	24,949	1,274
2043	0	0	0	132,591	28,757	1,662
2048	0	0	0	159,201	31,740	1,978

Table 5-5. SDG&E N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	20,830	15,677	468
2022	0	0	0	30,189	16,727	545
2028	0	0	0	86,343	21,517	958
2033	0	0	0	133,137	26,018	1,380
2038	0	0	0	179,931	31,008	1,889
2043	30	7	4	226,725	35,874	2,413
2048	196	18	8	273,520	40,207	2,937

Table 5-6. SDG&E N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	20,830	15,152	428
2028	0	0	0	36,859	17,895	636
2033	0	0	0	50,217	17,971	641
2038	0	0	0	63,575	20,763	896
2043	0	0	0	76,933	23,589	1,146
2048	0	0	0	90,291	25,756	1,352

In analyzing the SDG&E project, the following constraints (Table 5-7) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-7, only thermal violations associated with each constraint are reported.

Table 5-7. List of SDG&E Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2034	2040	2048
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore	N-1	Valley EFG - Newcomb-Skylark	2043	-	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22	N-1	Valley EFG - Elsinore-Fogarty	2043	-	-
Valley EFG-Tap 22	N-1	Valley EFG - Newcomb	2043	-	-

5.3.1.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the SDG&E Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between baseline and SDG&E for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 5-8 for the three forecasts.

Table 5-8. Cumulative Benefits – San Diego Gas & Electric

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	200,879	214,200	249,117
N-1	LAR (MWh)	6,375	21,684	75,545
N-1	IP (MW)	467	780	1,321
N-1	PFD (hr)	1,320	1,999	3,432
N-1	Flex-1 (MWh)	3,362,638	5,414,801	9,902,236
N-1	Flex-2-1 (MWh)	3,167,267	3,217,646	3,402,545
N-1	Flex-2-2 (MWh)	65,442	76,689	97,230
N-0	LAR (MWh)	22,748	55,563	132,227
N-0	IP (MW)	2,710	3,726	4,978
N-0	PFD (hr)	410	775	1,444

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SDG&E Project. In particular, the range of benefits is substantial in the N-1 category. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. The project also provides overall loss reduction primarily because it displaces loads at the southern border of the Valley South System service territory, thereby reducing the need for power to travel a longer distance from the source to delivery. Also, the flexibility benefits offered by the solution are limited in comparison to the ASP.

5.3.1.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided only in the near- and mid-term horizon. This trend is observable across all forecast sensitivities. Under N-0, 240 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 1,500 MWh under the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 132.2 GWh of avoided LAR.
2. With the SDG&E Project in service, the N-1 benefits in the system range from 6.3 to 72.6 GWh through all forecasts. The design of the SDG&E Project displaces two relatively large load centers located at the southern border of the Valley South System. By the nature of radial networks, all flows were originally moving in the direction of these loads. With load transfer and circuit reconfiguration, significant benefits are gained under N-1 outage conditions in the Valley South System. In the Spatial Base Forecast, by the year 2043, overloads due to N-1 events are observed in the system.
3. The project provides considerable flexibility to address planned, unplanned, or emergency outages in the system while also providing benefits to address needs under the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.
4. Following a HILP event, the SDG&E Project can recover approximately 280 MW of load from the Valley South System, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, SDG&E did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in the near-term horizon and under the lower range of forecast sensitivities.

5.3.2 SCE Orange County (Project C)

The SCE Orange County Project was evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.2.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection is a new substation with 220/115 kV transformation, southwest of SCE's Tenaja and Stadler Substations in the Valley South System.

2. Looping the San Onofre–Viejo 220 kV line to the new 220/115 kV substation. This configuration would include the construction of the new 230 kV double-circuit transmission line.
3. The proposed solution would transfer SCE's Tenaja and Stadler 115/12 kV Substations to the new 220/115 kV system through the construction of new 115 kV lines.
4. Normally-open circuit breakers at Skylark and Stadler Substations would create system tie-lines providing operational flexibility to accommodate future load transfers.

Figure 5-4 presents a high-level representation of the proposed configuration.

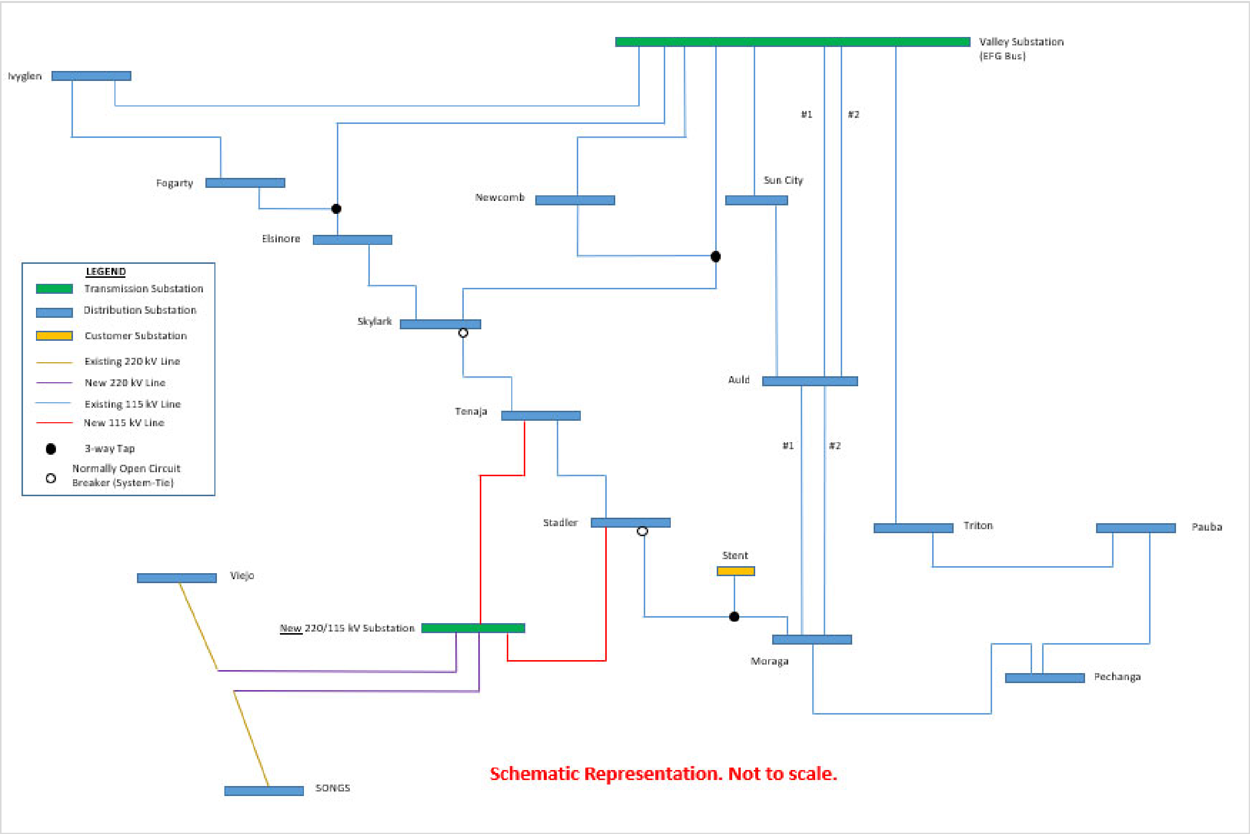


Figure 5-4. SCE Orange County Project Scope

5.3.2.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-9 for the Effective PV Forecast, Table 5-10 for the Spatial Base Forecast, and Table 5-11 for the PVWatts Forecast.

Table 5-9. SCE Orange County N-0 System Performance (Effective PV Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	2022	0	0	0	43,189
	2028	0	0	0	45,593
	2033	0	0	0	47,596
	2038	0	0	0	49,599
	2043	72	31	4	51,602
	2048	232	65	7	53,605

Table 5-10. SCE Orange County N-0 System Performance (Spatial Base Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	2021	0	0	0	43,574
	2022	0	0	0	44,330
	2028	0	0	0	41,444
	2033	0	0	0	45,672
	2038	183	55	5	49,899
	2043	536	111	11	54,126
	2048	1,426	159	27	58,353

Table 5-11. SCE Orange County N-0 System Performance (PVWatts Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	2022	0	0	0	43,189
	2028	0	0	0	45,593
	2033	0	0	0	45,187
	2038	0	0	0	46,843
	2043	0	0	0	48,500
	2048	0	0	0	50,156

5.3.2.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-12 for the Effective PV Forecast, Table 5-13 for the Spatial Base Forecast, and Table 5-14 for the PVWatts Forecast.

Table 5-12. SCE Orange County N-1 System Performance (Effective PV Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2022**	0	0	0	55,886	14,219	344
	2028	13	3	5	142,815	16,791	519
	2033	35	3	2	215,046	19,823	769
	2038	130	14	7	288,277	23,407	1,078
	2043	313	26	14	359,507	27,650	1,413
	2048	578	36	28	417,292	29,833	1,703

Table 5-13. SCE Orange County N-1 System Performance (Spatial Base Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2021**	5	3	2	55,886	14,711	375
	2022	10	3	2	77,708.23	15,692	438
	2028	38	5	4	208,643.16	20,192	798
	2033	176	17	8	317,755.59	24,412	1,169
	2038	497	32	24	426,868.03	29,138	1,633
	2043	1,179	46	37	535,980.47	33,790	2,108
	2048	2,275	74	56	645,092.91	37,969	2,570

Table 5-14. SCE Orange County N-1 System Performance (PVWatts Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2022**	0	0	0	55,886	14,219	344
	2028	13	3	5	103,236	16,791	519
	2033	15	3	6	142,695	16,863	523
	2038	32	3	10	182,154	19,485	735
	2043	95	10	21	221,613	22,133	968
	2048	159	16	23	261,072	24,165	1,146

In analyzing the SCE Orange County Project, the following constraints (Table 5-15) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-15, only thermal violations associated with each constraint are reported.

Table 5-15. List of SCE Orange County Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2034	2040	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2043	-	-
Auld-Moraga #1	N-1	Auld-Moraga #2	2033	2038	2048
Valley EFG-Triton	N-1	Moraga-Pechanga	2043	-	-
Valley EFG-Sun City	N-1	Valley EFG -Auld #1	2043	-	-
Valley EFG-Auld #1	N-1	Valley EFG -Sun City	2048	-	-
Valley EFG-Auld #1	N-1	Valley EFG -Auld #2	2043	-	-
Valley EFG-Sun City	N-1	Valley EFG -Auld #2	2043	-	-
Auld-Moraga #1	N-1	Valley EFG - Triton	2043	2048	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.2.4 Evaluation of Benefits

The established performance metrics were compared between baseline and SCE Orange County Project to quantify the overall benefits accrued over a 30-year study. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The cumulative value of the benefits over the 30-year horizon is presented in Table 5-16 for the three forecasts.

Table 5-16. Cumulative Benefits – SCE Orange County

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	193,424	187,601	203,637
N-1	LAR (MWh)	5,159	17,520	59,898
N-1	IP (MW)	337	447	661
N-1	PFD (hr)	1,055	1,785	2,923
N-1	Flex-1 (MWh)	583,840	1,278,674	4,209,439
N-1	Flex-2-1 (MWh)	3,200,515	3,255,754	3,449,007
N-1	Flex-2-2 (MWh)	69,270	81,467	103,655
N-0	LAR (MWh)	22,751	55,560	133,064
N-0	IP (MW)	2,713	3,724	4,986
N-0	PFD (hr)	411	776	1,456

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SCE Orange County Project. In particular, the range of benefits is substantial in the N-1 category and loss reduction. The project's contribution to loss reduction is primarily because it displaces loads at the southern border of the Valley South System service territory, thereby reducing the need for power to travel a longer distance from the source to point of delivery. Additionally, this project displaces loading on subtransmission lines with a significant contribution to overall system losses (namely, Tap 22–Skylark and Skylark–Tenaja) in the Valley South System. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. Also, the flexibility benefits offered by the solution are limited in comparison to the ASP.

5.3.2.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformer is avoided only in the near- and mid-term horizon. Under N-0, 230 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 1,400 MWh under Spatial Base Forecast for 2048. Across all sensitivities, the benefits range from 22.7 to 133 GWh of avoided LAR.
2. Considerable reduction in N-1 overloads is observed in the near-term and long-term horizons for all forecasts. With SCE Orange County Project in service, the N-1 LAR benefits in the system range from 5.1 to 57 GWh through all forecasts.
3. The project provides reasonable flexibility to address planned, unplanned, or emergency outages in the system while also providing benefits to address needs under the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.

4. Under peak loading conditions, the SCE Orange County Project would be able to approximately serve 280 MW of load from Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, the SCE Orange County project did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in the near- or mid-term horizon and under the lower range of forecast sensitivities.

5.3.3 Menifee (Project D)

The Menifee Project would construct a new substation located approximately 0.5 miles west of Valley Substation. The scope would include 500/115 kV transformation and associated 500 and 115 kV switch racks. Power would be supplied by looping in SCE's existing Serrano–Valley 500 kV line. SCE's existing Newcomb and Sun City distribution substations would be transferred to this new system providing relief on the Valley South System transformers. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.3.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection would be a new substation with two 500/115 kV transformers (including the spare) and associated facilities located approximately 0.5 miles west of Valley Substation. It would be provided power by looping in SCE's existing Serrano–Valley 500 kV line.
2. The proposed solution would transfer the loads at Newcomb and Sun City Substations in the Valley South System.
3. The 115 kV lines currently serving Newcomb and Sun City substations would be transferred to the new system involving a combination of new 115 kV lines and circuit reconfiguration.
4. Creates two system ties between the new system and the Valley South System through an open circuit breaker at Sun City and Valley Substations to provide operational flexibility.
5. Reconductor existing Auld–Sun City 115 kV line which would become the Valley–Auld–Sun City 115 kV line.
6. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-5 presents a high-level representation of the proposed configuration.

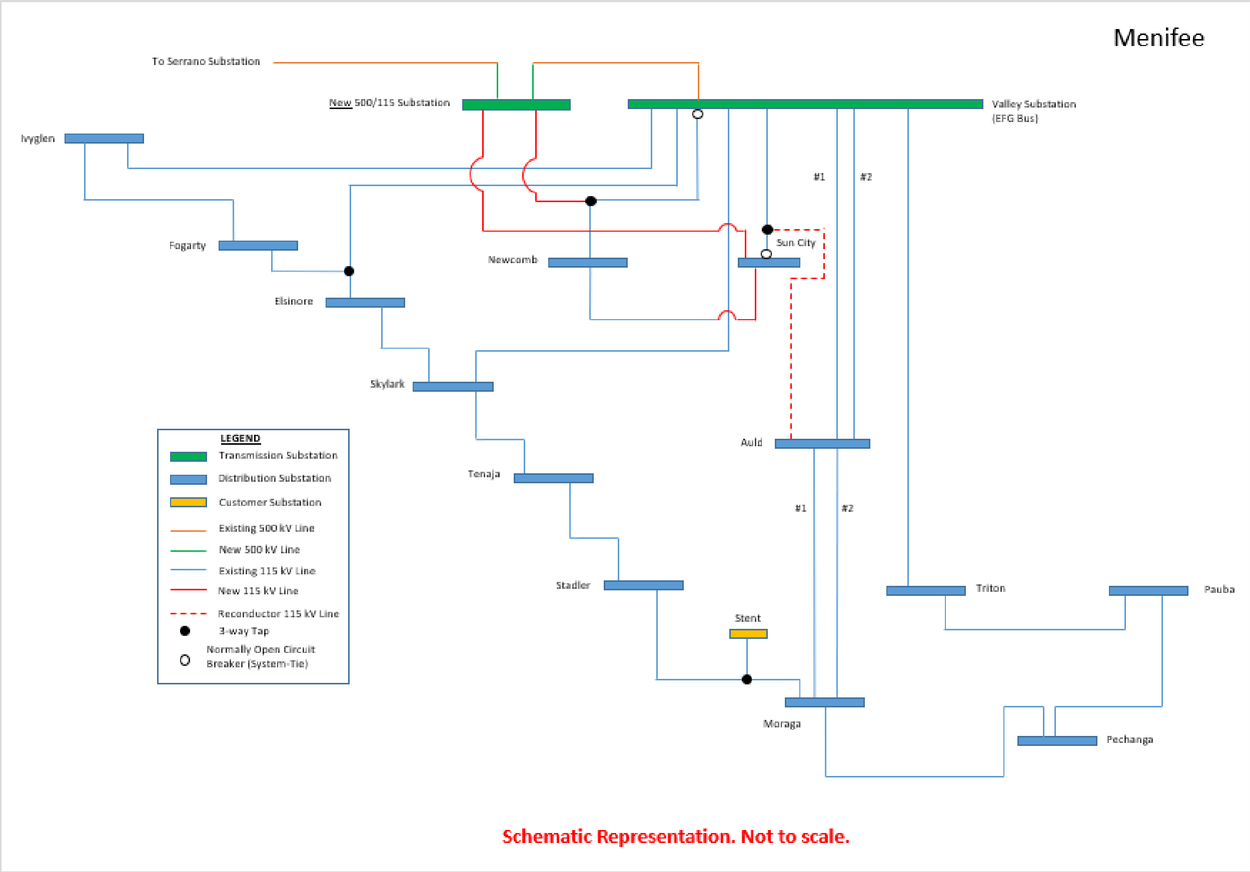


Figure 5-5. Menifee Project Scope

5.3.3.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-17 for the Effective PV Forecast, Table 5-18 for the Spatial Base Forecast, and Table 5-19 for the PVWatts Forecast.

Table 5-17. Menifee N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,898
2028	0	0	0	51,308
2033	0	0	0	53,316
2038	0	0	0	55,324
2043	3	3	1	57,332
2048	114	39	4	59,341

Table 5-18. Menifee N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,287
2022	0	0	0	50,035
2028	0	0	0	53,305
2033	0	0	0	56,030
2038	73	29	4	58,754
2043	385	83	8	61,479
2048	902	130	14	64,204

Table 5-19. Menifee N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,898
2028	0	0	0	51,308
2033	0	0	0	50,553
2038	0	0	0	52,316
2043	0	0	0	54,079
2048	0	0	0	55,855

5.3.3.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-20 for the Effective PV Forecast, Table 5-21 for the Spatial Base Forecast, and Table 5-22 for the PVWatts Forecast.

Table 5-20. SCE Menifee N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	24,267	571
2028	0	0	0	54,051	28,475	842
2033	4	2	2	81,311	33,145	1,161
2038	103	14	19	108,570	38,226	1,586
2043	472	22	67	135,830	42,887	2,025
2048	1040	38	155	163,090	46,332	2,369

Table 5-21. Menifee N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	25,088	616
2022	0	0	0	31,297	26,706	715
2028	4	2	2	91,039	33,690	1,202
2033	156	18	22	140,824	39,569	1,710
2038	722	37	70	190,610	45,496	2,286
2043	1,968	56	163	240,395	50,845	2,902
2048	3,737	68	272	290,181	55,391	3,458

Table 5-22. Menifee N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	24,267	571
2028	0	0	0	46,835	28,475	843
2033	0	0	0	68,082	28,590	850
2038	0.4	0.4	1	89,330	32,641	1,122
2043	47	10	11	110,577	36,471	1,426
2048	138	17	22	131,824	39,242	1,679

In analyzing the Menifee project, the following constraints (Table 5-23) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-23, only thermal violations associated with each constraint are reported.

Table 5-23. List of Menifee Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.3.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Menifee Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-24 for the three forecasts.

Table 5-24. Cumulative Benefits – Menifee

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	41,268	33,102	41,920
N-1	LAR (MWh)	5,724	15,368	51,103
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,370
N-1	Flex-1 (MWh)	2,795,076	5,356,744	9,661,860
N-1	Flex-2-1 (MWh)	2,860,352	2,885,882	3,029,498
N-1	Flex-2-2 (MWh)	59,402	69,398	87,588
N-0	LAR (MWh)	22,751	56,229	136,040
N-0	IP (MW)	2,713	3,930	5,371
N-0	PFD (hr)	411	800	1,519

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Menifee Project. By design, the project includes a permanent transfer of relatively large load centers in the Valley South System during the initial years. This provides significant N-0 system relief, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers.

5.3.3.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided only in the near-term horizon. Under N-0, 114 MWh of LAR is recorded in the Effective PV Forecast for 2048, and 985 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 135.6 GWh of avoided LAR.
2. N-1 overloads are observable in the mid-term and long-term horizons for all forecasts. With the project in service, the N-1 LAR benefits in the system range from 5.7 to 48 GWh through all forecast sensitivities.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South system.
4. Following a HILP event, the Menifee Project can serve a total of approximately 160 MW of load in Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, Menifee did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.4 Mira Loma (Project E)

The objective of this alternative is to take advantage of the Mira Loma system to provide a new source of supply into the Valley South service area. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.4.1 Description of Project Solution

1. Construct a new 220/115 kV substation with two transformers (including a spare) and associated facilities. The substation would be located near SCE's existing Mira Loma Substation and would be provided power by looping in an existing 220 kV line. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
2. Transfer load at Ivyglen and Fogarty Substations from the Valley South System to the new 220/115 kV system created.
3. Creates two system tie-lines between Valley South and the new system at Valley Substation and Fogarty Substation, respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-6 presents a high-level representation of the proposed configuration.

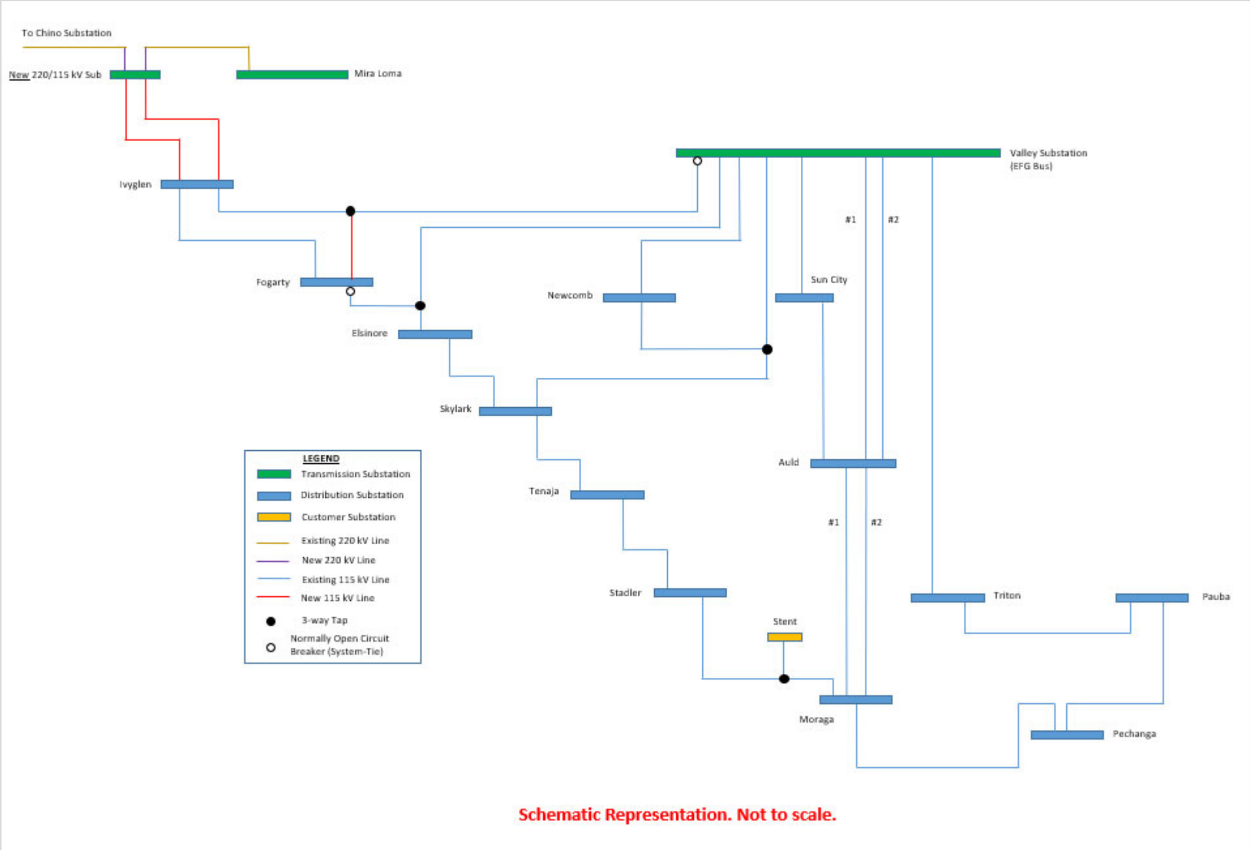


Figure 5-6. Tie-line to Mira Loma Project Scope

5.3.4.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-25 for the Effective PV Forecast, Table 5-26 for the Spatial Base Forecast, and Table 5-27 for the PVWatts Forecast.

Table 5-25. Mira Loma N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	82	31	4	53,021
2038	314	84	9	55,097
2043	807	138	22	57,173
2048	1,905	184	30	59,250

Table 5-26. Mira Loma N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,849
2022	0	0	0	49,618
2028	106	38	4	42,629
2033	607	104	12	48,041
2038	1,449	172	29	53,453
2043	3,365	238	45	58,864
2048	4,958	294	81	64,276

Table 5-27. Mira Loma N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	0	0	0	53,021
2038	58	24	4	55,097
2043	273	69	7	57,173
2048	526	184	30	59,250

5.3.4.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-28 for the Effective PV Forecast, Table 5-29 for the Spatial Base Forecast, and Table 5-30 for the PVWatts Forecast.

Table 5-28. Mira Loma N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	39,336	82,321	650
2028	0	0	0	99,638	87,598	944
2033	18	4	7	149,889	93,115	1,299
2038	94	15	27	200,140	98,884	1,766
2043	493	30	66	250,391	104,047	2,219
2048	1,151	40	127	300,643	107,821	2,609

Table 5-29. Mira Loma N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	39,336	83,384	708
2022	0	0	0	56,324	85,427	828
2028	12	4	7	158,254	93,744	1,345
2033	253	19	39	243,197	100,380	1,885
2038	822	36	114	328,139	106,913	2,513
2043	2427	57	246	413,081	112,783	3,150
2048	4599	77	442	498,023	117,771	3,772

Table 5-30. Mira Loma N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	39,336	82,321	650
2028	0	0	0	93,650	87,598	944
2033	0	0	0	138,912	87,737	951
2038	4	2	4	184,174	92,531	1,259
2043	64	9	16	229,436	96,915	1,601
2048	197	20	29	274,697	100,017	1,852

In analyzing the Mira Loma Project, the following constraints (Table 5-31) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-31, only thermal violations associated with each constraint are reported.

Table 5-31. List of Mira Loma Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2026	2031	2036
Valley EFG-Sun City	N-0	N/A (base case)	2044	-	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2044	-	-
Tap 39-Elsinore #1	N-0	N/A (base case)	2044	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2032	2038	2048
Valley EFG-Tap 39 #1	N-1	Valley EFG-Newcomb-Skylark	2032	2038	2043
Tap 39-Elsinore #1	N-1	Valley EFG-Newcomb-Skylark	2032	2038	2043
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2028	2033	2038
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2038	2043	-
Valley EFG-Sun City	N-1	Valley EFG-Auld #1	2038	2043	-
Valley EFG-Auld #1	N-1	Valley EFG-Sun City	2038	2045	-
Valley EFG-Tap 22#1	N-1	Valley EFG-Newcomb	2038	2043	-
Valley EFG-Auld #1	N-1	Valley EFG-Auld #2	2038	2043	-
Valley EFG-Sun City	N-1	Valley EFG-Auld #2	2038	2043	-
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2033	2038

5.3.4.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Mira Loma Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and Mira Loma for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-32 for all three forecasts.

Table 5-32. Cumulative Benefits – Mira Loma

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	48,851	40,333	47,004
N-1	LAR (MWh)	5,454	15,237	45,012
N-1	IP (MW)	355	421	603
N-1	PFD (hr)	1,041	1,125	214
N-1	Flex-1 (MWh)	623,316	3,255,037	6,500,106
N-1	Flex-2-1 (MWh)	1,252,410	1,263,410	1,326,687
N-1	Flex-2-2 (MWh)	55,850	65,168	82,069
N-0	LAR (MWh)	19,577	44,963	98,703
N-0	IP (MW)	1,720	2,270	2,721
N-0	PFD (hr)	362	554	935

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Mira Loma Project. Although the project demonstrates N-0 benefits in the short-term horizon, the project does not completely address the N-0 overload condition on the Valley South System transformers. In the Spatial Base Forecast, the project fails to satisfy needs in the short-term horizon as well, resulting in 106 MWh of LAR by 2028. The availability of system tie-lines does provide incremental flexibility to support emergency and maintenance conditions in the system. However, these benefits are limited in comparison to other solutions like ASP.

5.3.4.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, limited relief is available to overload conditions on the Valley South System transformers. Under N-0, 1,905 MWh of LAR is recorded under the Effective PV Forecast for 2048. Similarly, the LAR of 5,000 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range from 18.9 to 110 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 2.5 to 42.6 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South system.
4. Following a HILP event, Mira Loma can recover approximately 110 MW of load in Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, Mira Loma did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.5 Valley South to Valley North project (Project F)

The objective of this project is to transfer Newcomb and Sun City Substations from the Valley South system to the Valley North System. Under normal conditions, the Valley North System does not approach its transformer rated capacity until 2045 in the Spatial Base Forecast. In all other forecasts, the loading does not exceed transformer capacity. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North system have not been considered in the metrics.

The project was considered to leverage the capabilities of tie-lines to move loads between the Valley South System and the Valley North System. However, this transfer would not satisfy the short-term and long-term objectives of the projects. No incremental benefits are provided to the Valley South System in this configuration because no additional load can be transferred to Valley North during emergency or maintenance conditions in the network. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.5.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through the construction of new 115 kV lines.
2. Normally-open circuit breakers at the Valley South bus and Sun City Substation are maintained as system tie-lines between Valley North and Valley South for transfer flexibility.
3. Reconductor existing Auld–Sun City 115 kV line which would become the Valley–Auld–Sun City 115 kV line.
4. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-7 presents a high-level representation of the proposed configuration.

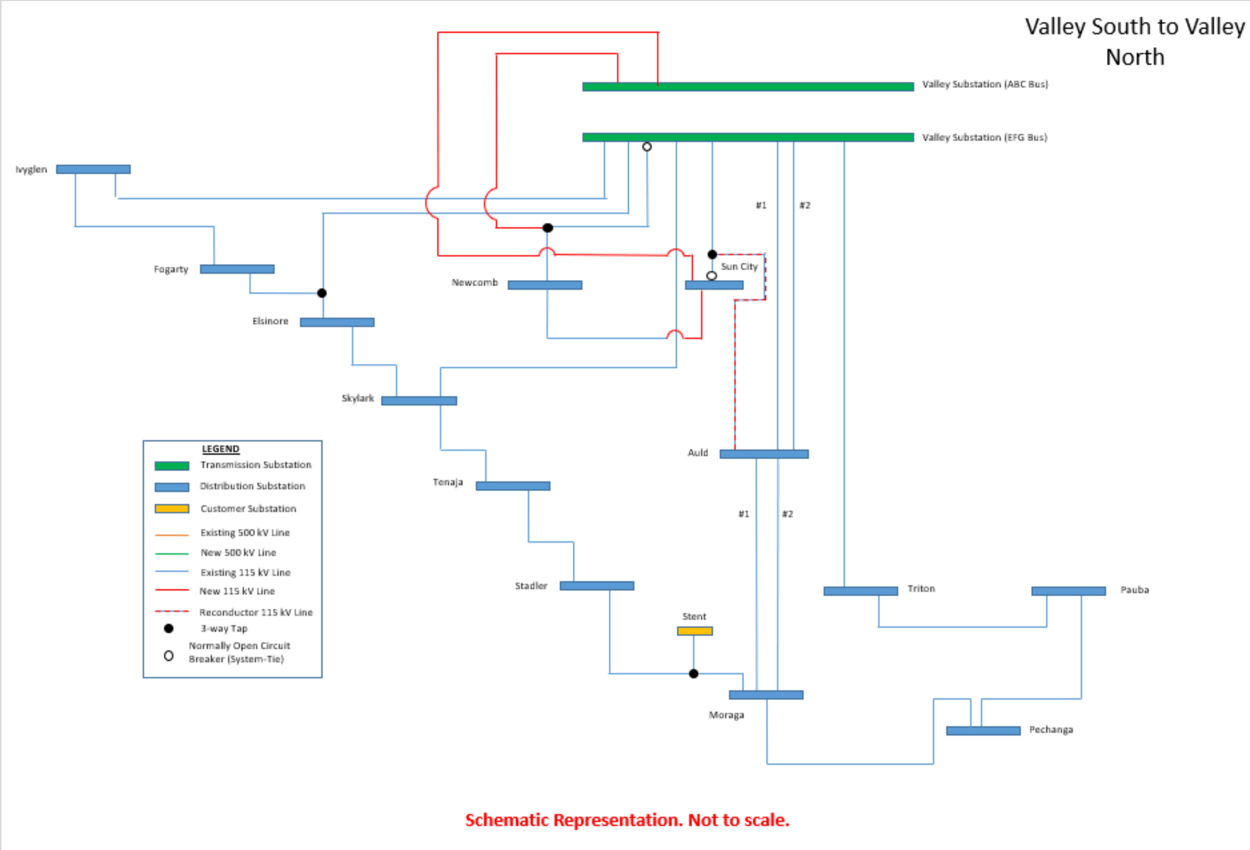


Figure 5-7. Tie-lines between Valley South and Valley North Project Scope

5.3.5.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-33 for the Effective PV Forecast, Table 5-34 for the Spatial Base Forecast, and Table 5-35 for the PVWatts Forecast.

Table 5-33. Valley South to Valley North N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	136	14	4	55,858
2043	779	44	20	57,898
2048	2,680	192	55	59,939

Table 5-34. Valley South to Valley North N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	305	56	13	56,568
2038	2,468	173	56	59,336
2043	8,146	310	104	62,104
2048	16,818	433	165	64,872

Table 5-35. Valley South to Valley North N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	94	49	6	54,713
2048	750	202	19	56,399

5.3.5.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-36 for the Effective PV Forecast, Table 5-37 for the Spatial Base Forecast, and Table 5-38 for the PVWatts Forecast.

Table 5-36. Valley South to Valley North N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	54,051	133,688	843
2033	4	2	2	81,311	139,702	1,161
2038	103	14	19	108,570	145,991	1,586
2043	472	27	67	135,830	151,619	2,025
2048	1040	38	155	163,090	155,733	2,369

Table 5-37. Valley South to Valley North N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	129,095	616
2022	0	0	0	31,297	140,388	1,202
2028	4	2	2	91,039	140,388	1,202
2033	156	18	22	140,824	147,622	1,710
2038	722	37	70	190,610	154,744	2,286
2043	1968	56	163	240,395	161,142	2,902
2048	3737	68	272	290,181	166,580	3,458

Table 5-38. Valley South to Valley North N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	46,835	133,688	843
2033	0	0	0	68,082	133,840	850
2038	0	0	1	89,330	139,065	1,122
2043	47	10	11	110,577	143,845	1,426
2048	138	17	22	131,824	147,226	1,679

In analyzing the Valley North to Valley South Project, the following constraints (Table 5-39) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-39, only thermal violations associated with each constraint are reported.

Table 5-39. List of Valley South to Valley North Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.5.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and the Valley South to Valley North Project for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-40 for the three forecasts.

Table 5-40. Cumulative Benefits – Valley South to Valley North

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,221	26,468
N-1	LAR (MWh)	5,724	15,368	50,734
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,371
N-1	Flex-1 (MWh)	2,795,076	5,356,743	9,661,860
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,398	87,588
N-0	LAR (MWh)	20,124	45,492	40,848
N-0	IP (MW)	1,910	3,211	2,380
N-0	PFD (hr)	328	537	288

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North Project. By design, the project includes a permanent transfer of large load centers in the Valley South System during initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. Additionally, the transformer overload condition is propagated to the Valley North System transformers starting from the year 2030 in the Spatial Base Forecast and 2036 in the Effective PV Forecast.

5.3.5.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South transformer is avoided in the near term and long-term horizon till the year 2043. However, the transfer of loads results in overloads on the Valley North transformer by the year 2037. 2,600 MWh of LAR is recorded under N-0 condition in the Effective PV Forecast and 16,800 MWh in the Spatial Base Forecast in the year 2048. Across all sensitivities, the benefits range from 20.1 to 45.4 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 5.7 to 47.9 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. During potential HILP events impacting Valley Substation, the project is unable to serve incremental load in the Valley South system.

5. Overall, the Valley South to Valley North Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.6 Valley South to Valley North to Vista (Project G)

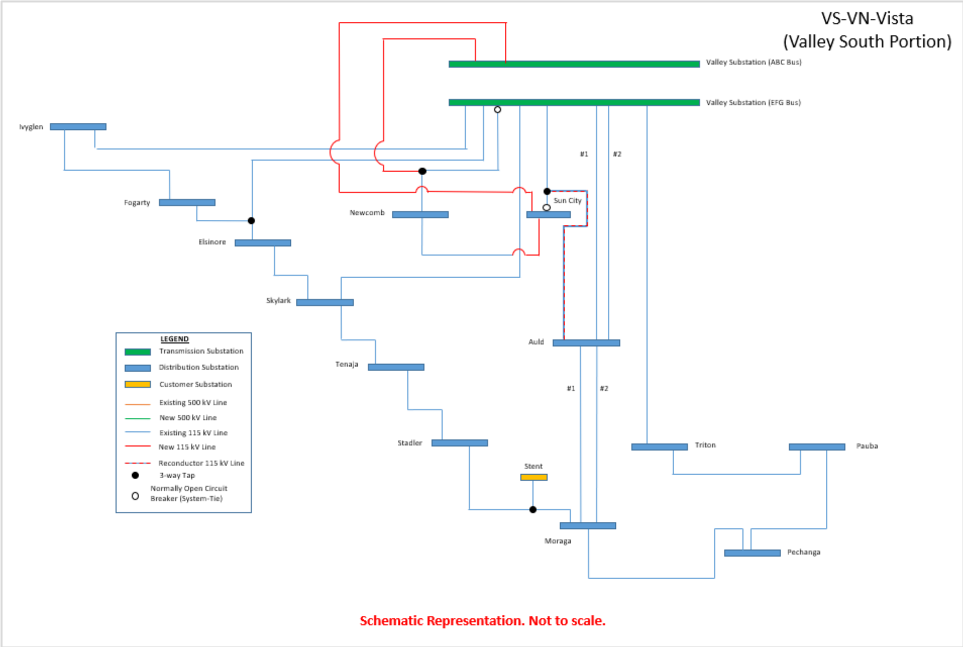
The objective of this project would be to transfer the loads at Newcomb and Sun City Substations to the Valley North System (identical to Project F). Additionally, the load at Moreno Substation in the Valley North System would be transferred to the Vista 220/115 kV system. The premise of this methodology is to relieve loading on the Valley North System to accommodate a load transfer from the Valley South System. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North System, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.6.1 Description of Project Solution

The proposed project would include the following components:

1. Moreno Substation is transferred to Vista 220/115 kV system through existing system tie-lines between Valley North and Vista Systems.
2. New 115 kV line construction to restore subtransmission network connectivity following transfer at Moreno Substation.
3. Normally-open circuit breaker at Moreno Substation to provide a system tie-line between the Vista system and the Valley North System.
4. The proposed project would also transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through the construction of new 115 kV lines (see Project F).
5. Normally-open circuit breakers at the Valley South bus and the Sun City Substation are maintained as system tie-lines between the Valley North System and the Valley South System for transfer flexibility.
6. Reconductor existing Auld–Sun City 115 kV line which would become the Valley–Auld–Sun City 115 kV line.
7. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-8 presents a high-level representation of the proposed configuration.



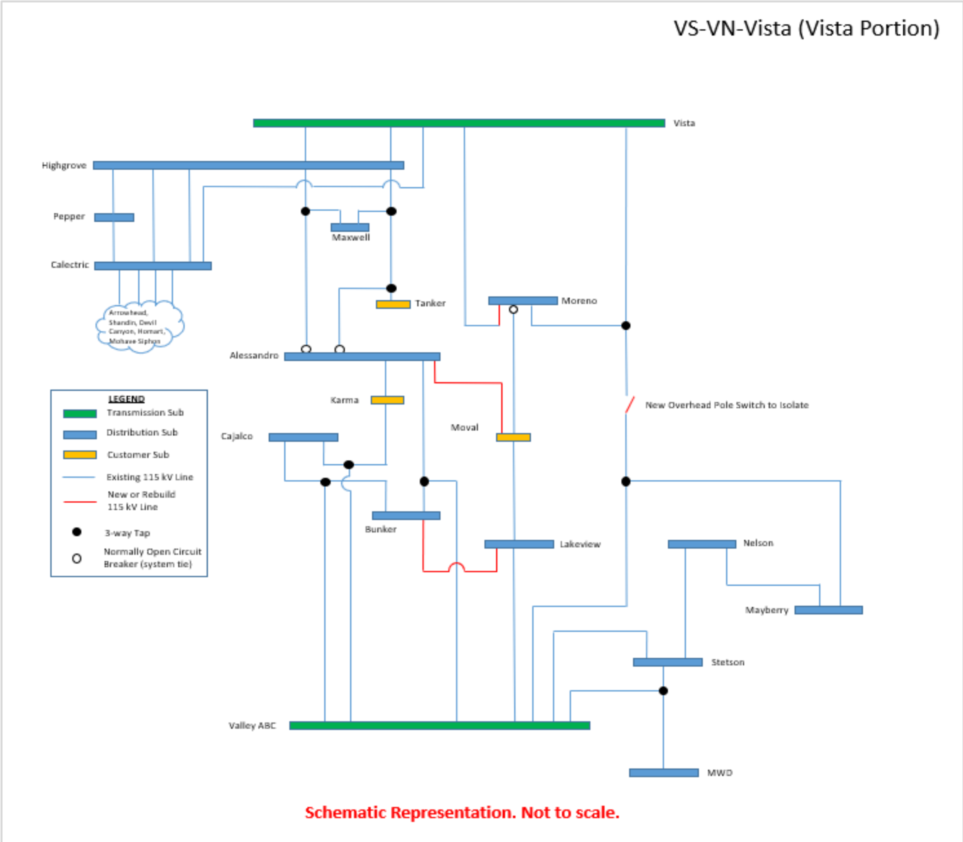


Figure 5-8. Tie-lines between Valley South to Valley North to Vista

5.3.6.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-41 for the Effective PV Forecast, Table 5-42 for the Spatial Base Forecast, and Table 5-43 for the PVWatts Forecast.

Table 5-41. Valley South to Valley North to Vista N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	54,225
2038	0	0	0	55,858
2043	83	31	6	57,898
2048	852	121	22	59,939

Table 5-42. Valley South to Valley North to Vista N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	756	112	23	59,336
2043	3,843	246	66	62,104
2048	9,003	365	119	64,872

Table 5-43. Valley South to Valley North to Vista N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	68	37	5	56,399

5.3.6.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-44 for the Effective PV Forecast, Table 5-45 for the Spatial Base Forecast, and Table 5-46 for the PVWatts Forecast.

Table 5-44. Valley South to Valley North to Vista N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	54,051	133,688	843
2033	4	2	2	81,311	139,702	1,161
2038	103	14	19	108,570	145,991	1,586
2043	472	27	67	135,830	151,619	2,025
2048	1040	38	155	163,090	155,733	2,370

Table 5-45. Valley South to Valley North to Vista N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	129,095	616
2022	0	0	0	31,297	140,388	1,202
2028	4	2	2	91,039	140,388	1,202
2033	156	18	22	140,824	147,622	1,710
2038	722	37	70	190,610	154,744	2,286
2043	1968	56	163	240,395	161,142	2,902
2048	3737	68	272	290,181	166,580	3,458

Table 5-46. Valley South to Valley North to Vista N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	46,835	133,688	843
2033	0	0	0	68,082	133,840	850
2038	0	0	1	89,330	139,065	1,122
2043	47	10	11	110,577	143,845	1,426
2048	138	17	22	131,824	147,226	1,679

In analyzing the Valley North to Valley South to Vista Project, the following constraints (Table 5-47) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-47, only thermal violations associated with each constraint are reported.

Table 5-47. List of Valley North to Valley South to Vista Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.6.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North to Vista Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and the Valley South to Valley North to Vista Project for each of the metrics.

The accumulative value of benefits over the 30-year horizon is presented in Table 5-48 for all three forecasts.

Table 5-48. Cumulative Benefits – Valley South to Valley North to Vista

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,221	26,468
N-1	LAR (MWh)	5,724	15,368	50,735
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,371
N-1	Flex-1 (MWh)	2,795,076	5,356,743	9,661,860
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,398	87,588
N-0	LAR (MWh)	22,613	53,700	91,349
N-0	IP (MW)	2,638	3,569	3,422
N-0	PFD (hr)	399	725	824

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North to Vista Project. By design, the project includes a permanent transfer of large load centers in Valley South during initial years. This provides significant N-0 system relief in Valley South, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. However, the transformer overload condition is propagated to the Valley North System transformers starting from the year 2041 in the Effective PV Forecast. The project also includes a transfer of load from the Valley North System to the Vista System. This temporarily remedies the system overload but does not provide relief over the long-term horizon.

5.3.6.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South system transformers is avoided in the near-term and long-term horizons until the year 2043. However, the transfer of loads results in overloads on the Valley North System transformers in the year 2041, with a transfer of loads to the Vista System. Under N-0, 852 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 9,000 MWh in the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.6 to 91.3 GWh of avoided LAR.
2. N-1 overloads are observable in the mid-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 5.7 to 47.9 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.

4. During potential HILP events affecting Valley Substation, the design of this project does not provide the ability to recover load in the Valley South System through leveraging capabilities of its system tie-lines.
5. Overall, Valley South to Valley North to Vista did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the System

5.3.7 Centralized BESS in Valley South Project (Project H)

The premise of this solution is to utilize BESS to be appropriately sized for meeting the reliability needs of the system. Storage has been separately sized for each of the forecasts under consideration, and their performance has been evaluated. Two locations in the Valley South System are considered, near SCE's existing Pechanga and Auld Substation, respectively, with a maximum capacity to accommodate 200 MW each. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.7.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection would be near Pechanga and/or Auld Substations following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
2. The initial BESS would be constructed near Pechanga Substation with an ultimate design capacity of 200 MW. Once this maximum value is reached, a subsequent and similar installation would be constructed near Auld Substation.
3. In order to meet the future needs of the Valley South System from 2021/2022 to 2048, the following storage sizes have been established. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026). The incremental storage sizes are presented in Table 5-49 through Table 5-51.
4. Due to the radial design of the Valley South System under the study, locating the BESS interconnection near Pechanga or Auld Substations would not result in significant differences to N-0 system performance and reliability indices.
5. In the Valley South system, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-49. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	MW	MWh	MW	MWh
2021	110	433		
2026	64	436		
2031	36	279	28	227
2036			61	485
2041			54	491
2046			18	191
Total Battery Size (including contingency): **371 MW / 2542 MWh**				

Table 5-50. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	MW	MWh	MW	MWh
2022	71	216		
2027	47	281		
2032	57	377		
2037	34	264	18	153
2042			46	375
Total Battery Size (including contingency): **273 MW/ 1666 MWh**				

Table 5-51. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2022	68	216
2027	5	31
2032	46	237
2037	45	286
2042	38	299
Total Battery Size (including contingency): **202 MW/ 1069 MWh**		

Figure 5-9 presents a high-level representation of the proposed configuration. The proposed configuration would loop into or tap along the Pechanga to Pauba circuit and Auld to Moraga circuit.

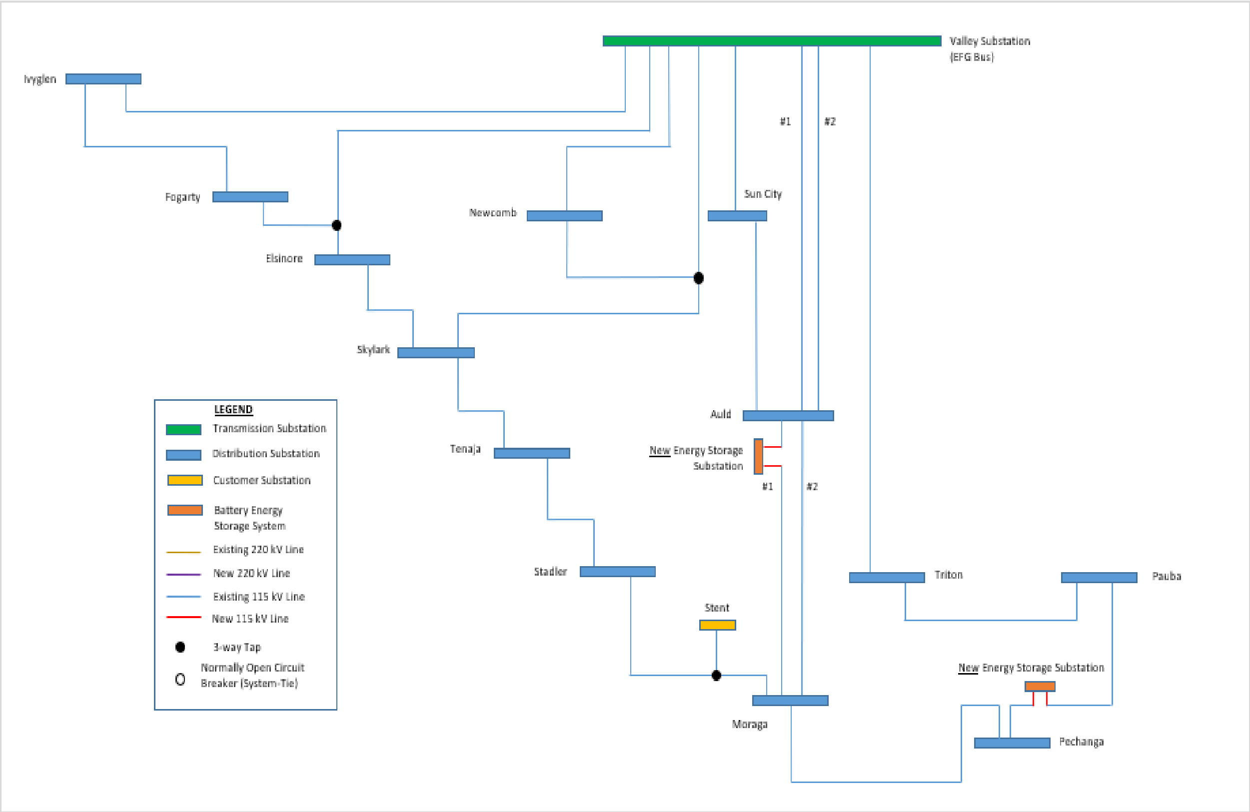


Figure 5-9. Energy Storage at Pechanga and/or Auld Substation as part of the Centralized BESS in the Valley South Project Scope

5.3.7.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-52 for the Effective PV Forecast, Table 5-53 for the Spatial Base Forecast, and Table 5-54 for the PVWatts Forecast.

Table 5-52. Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,531
2028	0	0	0	50,808
2033	0	0	0	52,705
2038	0	0	0	54,602
2043	0	0	0	56,499
2048	0	0	0	58,396

Table 5-53. Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,908
2022	0	0	0	49,636
2028	0	0	0	52,664
2033	0	0	0	55,188
2038	0	0	0	57,711
2043	0	0	0	60,235
2048	0	0	0	62,758

Table 5-54. Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,531
2028	0	0	0	50,808
2033	0	0	0	50,455
2038	0	0	0	52,037
2043	0	0	0	53,618
2048	0	0	0	55,199

5.3.7.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-55 for the Effective PV Forecast, Table 5-56 for the Spatial Base Forecast, and Table 5-57 for the PVWatts Forecast.

Table 5-55. Centralized BESS N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	26,492	127,935	2,138
2028	0	0	0	81,951	133,688	2,765
2033	0	0	0	123,478	139,702	3,483
2038	0	0	0	165,004	145,991	4,337
2043	0	0	0	206,531	151,619	5,136
2048	0	0	0	248,058	155,733	5,738

Table 5-56. Centralized BESS N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	26,492	129,095	2,253
2022	0	0	0	32,545	131,322	2,486
2028	0	0	0	68,868	140,388	3,577
2033	0	0	0	99,136	147,622	4,567
2038	0	0	0	129,405	154,744	5,595
2043	0	0	0	159,674	161,142	6,584
2048	31	7	4	189,942	166,580	7,466

Table 5-57. Centralized BESS N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	26,491	127,935	2,138
2028	0	0	0	47,161	133,688	2,765
2033	0	0	0	64,385	133,840	2,780
2038	0	0	0	81,609	139,065	3,404
2043	0	0	0	98,833	143,845	4,047
2048	0	0	0	116,058	147,226	4,516

In analyzing the Centralized BESS in Valley South Project, the following constraints (Table 5-58) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-58, only thermal violations associated with each constraint are reported.

Table 5-58. List of Centralized BESS in Valley South Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Valley EFG-Tap 22 #1	N-1	Valley EFG-Newcomb	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Moraga-Tap 150	N-1	Skylark-Tenaja	2048	-	-

5.3.7.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Centralized BESS in Valley South Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and the Centralized BESS in Valley South.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-59 for the three forecasts.

Table 5-59. Cumulative Benefits – Centralized BESS in Valley South

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	52,822	50,796	67,206
N-1	LAR (MWh)	6,375	21,684	75,132
N-1	IP (MW)	467	780	1,375
N-1	PFD (hr)	1,320	1,999	3,456
N-1	Flex-1 (MWh)	2,938,356	4,067,234	10,993,065
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	834	2,111	5,182
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Centralized BESS in Valley South Project. The project provides significant relief addressing the N-0 and N-1 needs in the Valley South System. However, the solution does not offer any flexibility in terms of system tie-lines and capabilities to support planned, unplanned, or emergency conditions in the system. The batteries alone cannot complement the system needs during HILP events since they are not configured to operate as microgrids, nor are they a viable alternative to system tie-lines for extended events of extended duration.

5.3.7.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South transformer is avoided in the near-term and long-term horizon. Across all sensitivities, the benefits range from 22.7 to 140.9 GWh of avoided LAR.
2. Minimal N-1 overloads are observable in the long-term horizon for all forecasts. With the project in service, the N-1 LAR benefits in the system range from 6.3 to 73.2 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Due to HILP events affecting Valley Substation, the project is unable to serve incremental load in the Valley South System. The BESS installed capacity cannot be effectively be translated to any benefits due to limited opportunities for charging that could reasonably be expected during HILP events.
5. Overall, the Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. While the project addressed N-0 and N-1 needs across the horizon, the solution offers limited flexibility benefits with higher implementation costs.

5.3.8 Valley South to Valley North and Distributed BESS in Valley South project (Project I)

The objective of this project is to transfer Newcomb and Sun City Substations to Valley North (identical to Project F) along with the procurement of distribution-system connected BESS (utility-scale DER) in the Valley South System. In this analysis, a load transfer from the Valley South System to the Valley North System precedes the investment in a distributed BESS. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North System, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast under study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.8.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North system through new 115 kV construction and reconfiguration.
2. Normally-open circuit breakers at the Valley South system bus and at Sun City Substation are maintained as system tie-lines between the Valley North system and the Valley South System for transfer flexibility.
3. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The initial need year is identified as 2036 and 2043 in the Spatial Base and Effective PV Forecasts, respectively. No procurements are required in the PVWatts Forecast.
4. Storage investments totaling 50 MW are made at Auld, Elsinore, and Moraga Substations, which have been identified as having sufficient space to likely accommodate on-site BESS installations. The 50 MW total of BESS was modeled as 10 MW at Auld, 20 MW at Elsinore, and 20 MW at Moraga Substation.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-10 presents a high-level representation of the proposed configuration.

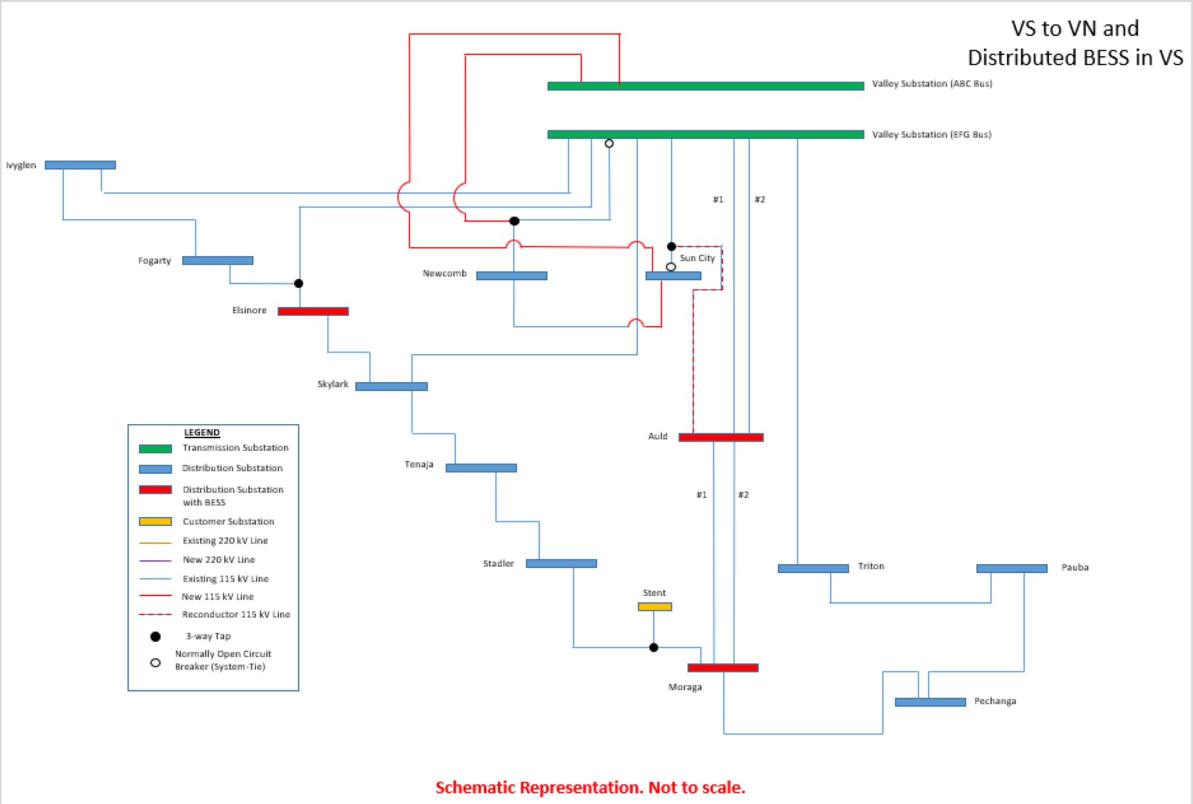


Figure 5-10. Tie-lines between Valley South and Valley North and Distributed BESS in Valley South Project Scope

5.3.8.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-60 for the Effective PV Forecast, Table 5-61 for the Spatial Base Forecast, and Table 5-62 for the PVWatts Forecast.

Table 5-60. Valley South to Valley North and Distributed BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	136	14	4	55,858
2043	775	43	19	57,898
2048	2,567	156	57	59,923

Table 5-61. Valley South to Valley North and Distributed BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	305	56	13	56,568
2038	2,388	143	51	59,310
2043	7,789	253	102	62,034
2048	16,127	371	159	64,749

Table 5-62. Valley South to Valley North and Distributed BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	94	49	6	54,713
2048	750	202	19	56,399

5.3.8.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-63 for the Effective PV Forecast, Table 5-64 for the Spatial Base Forecast, and Table 5-65 for the PVWatts Forecast.

Table 5-63. Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,330	127,935	571
2028	0	0	0	44,298	133,688	843
2033	4	2	2	68,743	139,702	1,161
2038	103	14	19	92,170	145,991	1,586
2043	324	18	45	113,095	151,619	2,025
2048	614	23	80	134,586	155,733	2,370

Table 5-64. Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,331	129,095	616
2022	0	0	0	27,808	131,322	715
2028	4	2	2	66,672	140,388	1,202
2033	156	18	22	99,058	147,622	1,710
2038	488	23	69	131,445	154,744	2,247
2043	1357	33	155	163,831	161,142	2,823
2048	2506	65	243	196,218	166,580	3,320

Table 5-65. Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331	127,935	571
2028	0	0	0	46,816	133,688	843
2033	0	0	0	68,054	133,840	850
2038	0.4	0.4	1	89,293	139,065	1,122
2043	47	10	11	110,530	143,845	1,426
2048	138	17	22	131,768	147,226	1,679

In analyzing the Valley South to Valley North and Distributed BESS in Valley South Project, the following constraints (Table 5-66) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from 2022 and beyond).

In Table 5-66, only thermal violations associated with each constraint are reported.

Table 5-66. List of Valley South to Valley North and Distributed BESS in Valley South project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley North Transformer	N-0	N/A (base case)	2030		-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	-	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	2043	-
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2033	-

5.3.8.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North and Distributed BESS in Valley South Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the project for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-67 for the three forecasts.

Table 5-67. Cumulative Benefits – Valley South to Valley North and Distributed BESS in Valley South

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,245.60	27,277.58
N-1	LAR (MWh)	5,724	17,090.60	57,832
N-1	IP (MW)	366	526.95	790.25

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-1	PFD (hr)	1,196	1,389	1,459
N-1	Flex-1 (MWh)	2,275,927	5,741,522	10,977,462
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,405	88,541
N-0	LAR (MWh)	20,124	45,854	45,131
N-0	IP (MW)	1,910	3,416	2,967
N-0	PFD (hr)	328	561	330

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North and Distributed BESS in Valley South Project. By design, the project includes a permanent transfer of large load centers from the Valley South System during the initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. The presence of a distributed BESS solution in the Valley South System alleviates the capacity needs in the Valley South System in the Effective PV Forecast, but not under the Spatial Base Forecast sensitivity. Additionally, the transformer overload condition is propagated to the Valley North System transformers beginning in the year 2030 in the Spatial Base Forecast.

5.3.8.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloads on the Valley South System transformers are avoided in the near-term and long-term horizon until the year 2033. However, the transfer of loads results in overloads on the Valley North System transformers by the year 2037. Under N-0, 2,600 MWh of LAR is recorded in the Effective PV Forecast for 2048, and 16,200 MWh is recorded under the Spatial Base Forecast sensitivity. Across all sensitivities, the benefits range from 20.1 to 45.1 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 5.7 GWh to 55 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Should a HILP event affect Valley Substation, this solution is unable to serve incremental load in the Valley South system by leveraging the capabilities of system tie-lines. Additionally, the BESS capacity cannot be effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.
5. Overall, the Valley South to Valley North and Distributed BESS in Valley South Project did not demonstrate comparable levels of performance in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.9 SDG&E and Centralized BESS in Valley South (Project J)

This project proposes to construct a new 230/115 kV substation provided power by the SDG&E transmission system (identical to Project B). This solution is coupled with Centralized BESS in Valley South (identical to Project H) to provide further relief over the long-term horizon. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.9.1 Description of Project Solution

The proposed project would transfer Pechanga and Pauba Substations to a new 230/115 kV transmission substation receiving 230 kV service from the SDG&E electric system. The proposed project would include the following components:

1. The point of interconnection would be a new 230/115 kV substation between the SCE-owned Pechanga Substation and SDG&E-owned Talega–Escondido 230 kV transmission line to the south. Two 230/115 kV transformers (one load-serving and one spare).
2. New double-circuit 230 kV transmission line looping the new substation into SDG&E's Talega–Escondido 230 kV transmission line.
3. New 115 kV line construction to allow the transfer of Pechanga and Pauba Substations from Valley South to new 230/115 kV substation.
4. Create system tie-lines between the new 230/115 kV system and the Valley South System through normally-open circuit breakers at SCE's Triton and Moraga Substations to provide operational flexibility and to accommodate potential future additional load transfers.
5. Rebuild of existing Pechanga Substation and/or expansion of existing property at Pechanga Substation to accommodate required new 115 kV switch rack positions.
6. BESS would be installed near Auld Substations following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
7. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-68 through Table 5-70, for all forecasts.
8. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026).
9. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-68. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	MW	MWh
2039	65	189
2044	25	130
Total Battery Size (including contingency): **90 MW/319 MWh**		

Table 5-69. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	MW	MWh
2033	82	262
2038	56	323
2043	49	323
Total Battery Size (including contingency): **187 MW/908 MWh**		

Table 5-70. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	MW	MWh
2048	20	64
Total Battery Size (including contingency): **20 MW/64 MWh**		

Figure 5-11 presents a high-level representation of the proposed configuration.

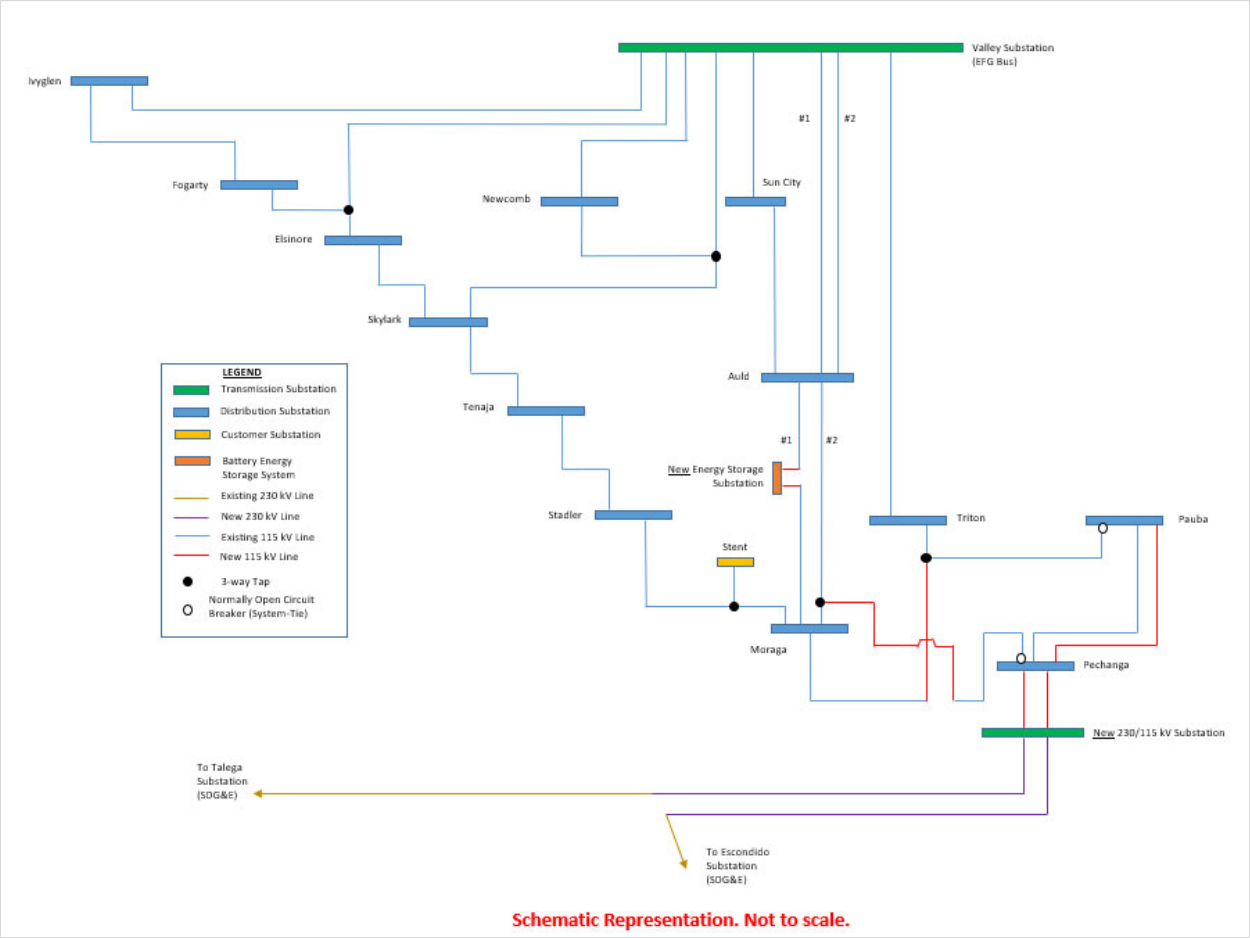


Figure 5-11. SDG&E and Centralized BESS in Valley South Project Scope

5.3.9.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions in the system are presented in Table 5-71 for the Effective PV Forecast, Table 5-72 for the Spatial Base Forecast, and Table 5-73 for the PVWatts Forecast.

Table 5-71. SDG&E and Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	48,529
2038	0	0	0	50,505
2043	0	0	0	51,023
2048	0	0	0	51,176

Table 5-72. SDG&E and Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	44,182
2022	0	0	0	44,715
2028	0	0	0	46,963
2033	0	0	0	48,837
2038	0	0	0	50,687
2043	0	0	0	52,537
2048	0	0	0	54,387

Table 5-73. SDG&E and Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	45,310
2038	0	0	0	46,470
2043	0	0	0	47,630
2048	0	0	0	48,790

5.3.9.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 5-74 for the Effective PV Forecast, Table 5-75 for the Spatial Base Forecast, and Table 5-76 for the PVWatts Forecast.

Table 5-74. SDG&E and Centralized BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	16,761	15,152	428
2028	0	0	0	42,455	17,895	636
2033	0	0	0	63,537	21,123	926
2038	0	0	0	84,920	24,949	1,274
2043	0	0	0	106,303	28,757	1,662
2048	0	0	0	128,102	31,740	1,977

Table 5-75. SDG&E and Centralized BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	16,761	15,677	468
2022	0	0	0	22,124	16,727	545
2028	0	0	0	54,299	21,517	958
2033	0	0	0	81,112	26,018	1,380
2038	0	0	0	107,924	31,008	1,889
2043	0	0	0	134,737	35,874	2,409
2048	0	0	0	161,550	40,207	2,924

Table 5-76. SDG&E and Centralized BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	16,761	15,152	428
2028	0	0	0	33,355	17,895	636
2033	0	0	0	47,182	17,971	641
2038	0	0	0	61,010	20,763	896
2043	0	0	0	74,838	23,589	1,146
2048	0	0	0	88,666	25,756	1,352

In analyzing the SDG&E and Centralized BESS in Valley South project, no constraints were found to be binding under N-0 and N-1 conditions.

5.3.9.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the SDG&E and Centralized BESS in Valley South to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the SDG&E and Centralized BESS for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-77 for the three forecasts.

Table 5-77. Cumulative Benefits – SDG&E and Centralized BESS

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	195,515	214,367	249,947
N-1	LAR (MWh)	6,375	21,684	76,225
N-1	IP (MW)	467	780	1,397
N-1	PFD (hr)	1,320	1,999	3,468
N-1	Flex-1 (MWh)	3,439,502	5,894,261	11,526,786
N-1	Flex-2-1 (MWh)	3,167,267	3,217,646	3,402,545
N-1	Flex-2-2 (MWh)	65,442	76,689	97,285
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SDG&E and Centralized BESS in Valley South Project. With the BESS investments, the range of benefits is substantial in the N-1 category and N-0 category. However, the flexibility benefits offered by the solution are limited in comparison to the ASP.

5.3.9.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the near-term and long-term horizon. This trend is observable across all considered forecasts. Across all sensitivities, the benefits range from 22.7 to 140.9 GWh of avoided LAR.

2. With SDG&E and Centralized BESS in Valley South Project in service, the N-1 LAR benefits in the system range from 6.3 to 73.3 GWh through all forecasts. With the incremental investment in BESS, no N-1 overloads were observed in the system.
3. The project provides considerable flexibility to address planned and unplanned or emergency outages in the system while also providing benefits to address needs under the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.
4. Should a HILP event occur and impact Valley Substation, the SDG&E and Centralized BESS in Valley South Project can recover approximately 280 MW of load in the Valley South System by leveraging the capabilities of its system tie-lines. The BESS installed capacity alone cannot be effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.
5. Overall, the SDG&E and Centralized BESS Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in combination with storage investments.

5.3.10 Mira Loma and Centralized BESS in Valley South project (Alternatives K)

The objective of this alternative is to take advantage of the Mira Loma system to provide a new source of supply into the Valley South service area. To address capacity needs across the 30-year horizon, this solution is coupled with Centralized BESS in Valley South. This is essentially a combination of Projects E and H. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.10.1 Description of Project Solution

1. Construct a new 220/115 kV substation with two transformers (including a spare) and associated facilities. The substation would be located near SCE's existing Mira Loma Substation and would be provided power by looping in an existing 220 kV line. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
2. Transfer load at Ivyglen and Fogarty Substations from the Valley South System to the new 220/115 kV System created.
3. Creates two system tie-lines between Valley South and the new system at Valley Substation and Fogarty Substation, respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
6. BESS would be installed near Pechanga or Auld Substations following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
7. The initial BESS would be constructed near Pechanga Substation with an ultimate design capacity of 200 MW. Once this maximum value is reached, a subsequent and similar installation would be constructed near Auld Substation.

8. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-78 through Table 5-80, for all forecasts.
9. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026).
10. Due to the radial design of the Valley South system under the study, locating the BESS interconnection near Pechanga or Auld Substations would not result in significant differences to N-0 system performance and reliability indices.
11. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-78. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	MW	MWh	MW	MWh
2026	99	299		
2031	52	373		
2036	61	463		
2041			54	427
2046			18	157
Total Battery Size: **284 MW/ 1719 MWh**				

Table 5-79. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2031	83	247
2036	48	303
2041	43	296
2046	12	106
Total Battery Size: **186 MW/ 952 MWh**		

Table 5-80. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2036	66	195
2041	34	194
2046	9	62
Total Battery Size: **109 MW/ 451 MWh**		

Figure 5-12 presents a high-level representation of the proposed configuration.

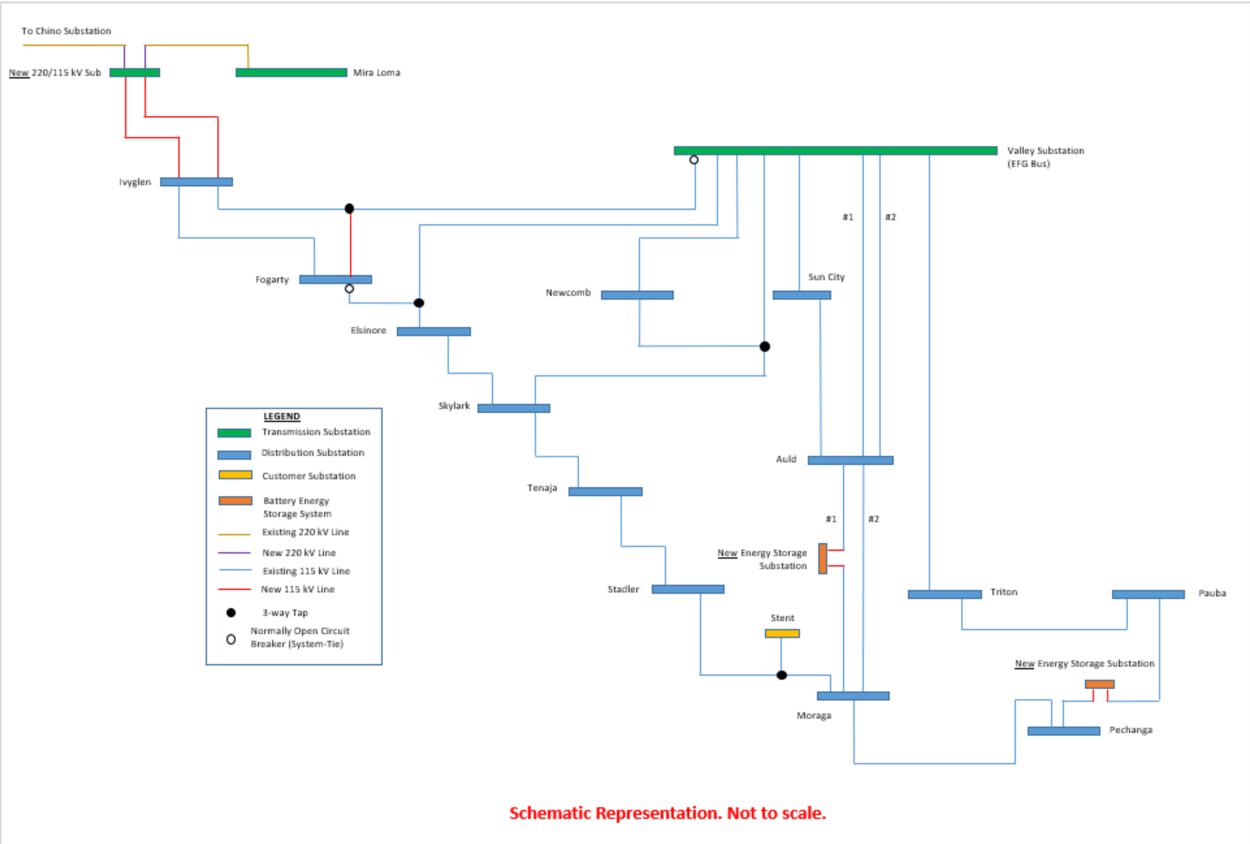


Figure 5-12. Tie-line to Mira Loma and Centralized BESS in Valley South Project Scope

5.3.10.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-81 for the Effective PV Forecast, Table 5-82 for the Spatial Base Forecast, and Table 5-83 for the PVWatts Forecast.

Table 5-81. Mira Loma and Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,456
2028	0	0	0	48,017
2033	0	0	0	50,408
2038	0	0	0	53,323
2043	0	0	0	56,238
2048	0	0	0	59,154

Table 5-82. Mira Loma and Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,849
2022	0	0	0	49,618
2028	0	0	0	42,629
2033	0	0	0	48,041
2038	0	0	0	53,453
2043	0	0	0	58,864
2048	0	0	0	64,276

Table 5-83. Mira Loma and Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	0	0	0	53,021
2038	0	0	0	55,097
2043	0	0	0	57,173
2048	0	0	0	59,250

5.3.10.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 5-84 for the Effective PV Forecast, Table 5-85 for the Spatial Base Forecast and Table 5-86 for the PVWatts Forecast.

Table 5-84. Mira Loma and Centralized BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	34,120	82,321	650
2028	0	0	0	87,130	87,598	944
2033	0	0	0	130,912	91,967	1,299
2038	0	0	0	174,909	98,884	1,766
2043	5	2.5	2	218,906	104,047	2,217
2048	15.2	2.5	9	262,902	107,821	2,602

Table 5-85. Mira Loma and Centralized BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	34,121	83,384	708
2022	0	0	0	43,257	85,427	828
2028	0	0	0	98,075	93,744	1,345
2033	0	0	0	143,757	100,380	1,885
2038	11	3	6	189,439	106,913	2,508
2043	35	4	20	253,121	112,783	3,132
2048	182	11	61	280,803	117,771	3,729

Table 5-86. Mira Loma and Centralized BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	34,120	82,321	650
2028	0	0	0	86,2221	87,598	944
2033	0	0	0	129,639	87,737	951
2038	0	0	0	173,057	92,531	1,259
2043	0	0	0	216,474	96,915	1,601
2048	0	0	0	259,892	100,017	1,852

In analyzing the Mira Loma and Centralized BESS in Valley South project, the following constraints (Table 5-87) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-87, only thermal violations associated with each constraint are reported.

Table 5-87. List of Mira Loma and Centralized BESS in Valley South Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley EFG-Tap 39 #1	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore #1	N-1	Valley EFG-Newcomb-Skylark	2043	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2038	2048	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Valley EFG-Tap 22#1	N-1	Valley EFG-Newcomb	2048	-	-

5.3.10.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Mira Loma and Centralized BESS in Valley South Project to quantify the overall benefits accrued over 30-year study horizons. The benefits are quantified as the difference between the baseline and the project for each of the metrics.

The accumulative values of the benefits over the 30-year horizon are presented in Table 5-88 for the three forecasts.

Table 5-88. Cumulative Benefits – Mira Loma and Centralized BESS in Valley South

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	50,251	41,338	51,951
N-1	LAR (MWh)	6,375	21,303	72,541
N-1	IP (MW)	467	760	1,333
N-1	PFD (hr)	1,320	1,962	3,152
N-1	Flex-1 (MWh)	893,598	3,831,571	9,614,215
N-1	Flex-2-1 (MWh)	1,252,410	1,263,410	1,326,687
N-1	Flex-2-2 (MWh)	55,850	65,194	82,304
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Mira Loma and Centralized BESS in Valley South Project. The project completely addresses N-0 needs in the Valley South System. The capacity afforded by the system tie-lines does not fully support emergency and maintenance conditions in the system.

5.3.10.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the study horizon. This trend is observable across all considered forecasts. Across all sensitivities, the benefits range from 22.7 to 140.9 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 6.3 to 72.5 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that may occur in the Valley South System.
4. Should a HILP event occur and impact Valley Substation, the Mira Loma and Centralized BESS in Valley South Project can recover approximately 110 MW of load in the Valley South System by leveraging the capabilities of its system tie-lines. The BESS installed capacity alone cannot be effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.
5. Overall, the Mira Loma and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers a limited advantage in addressing the N-1 and flexibility needs of the system.

5.3.11 Valley South to Valley North and Centralized BESS in Valley South and Valley North (Project L)

The objective of this project would be to transfer the loads at Newcomb and Sun City substations to Valley North (identical to Project #F). Additionally, BESS installation would be constructed within both the Valley South and Valley North systems to provide relief over the long-term horizon. This is a combination of Projects F and H. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North system have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.11.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through the construction of new 115 kV lines.
2. Normally-open circuit breakers at the Valley South bus and at Sun City Substation are maintained as system tie-lines between Valley North and Valley South for transfer flexibility.
3. Reconductor existing Auld–Sun City 115 kV line, which would become the Valley–Auld–Sun City 115 kV line.
4. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
5. BESS would be installed near Pechanga in Valley South and Allesandro Substation in Valley North following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
6. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-89 through Table 5-91, for all forecasts.
7. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026).
8. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-89. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	MW	MWh	MW	MWh
2030			97	375
2035(VS-2036)	81	242	77	635
2042 (VS-2041)	49	291	72	704
2045(VS-2046)	18	114	39	418
Total Battery Size: **433 MW/ 2779 MWh**				

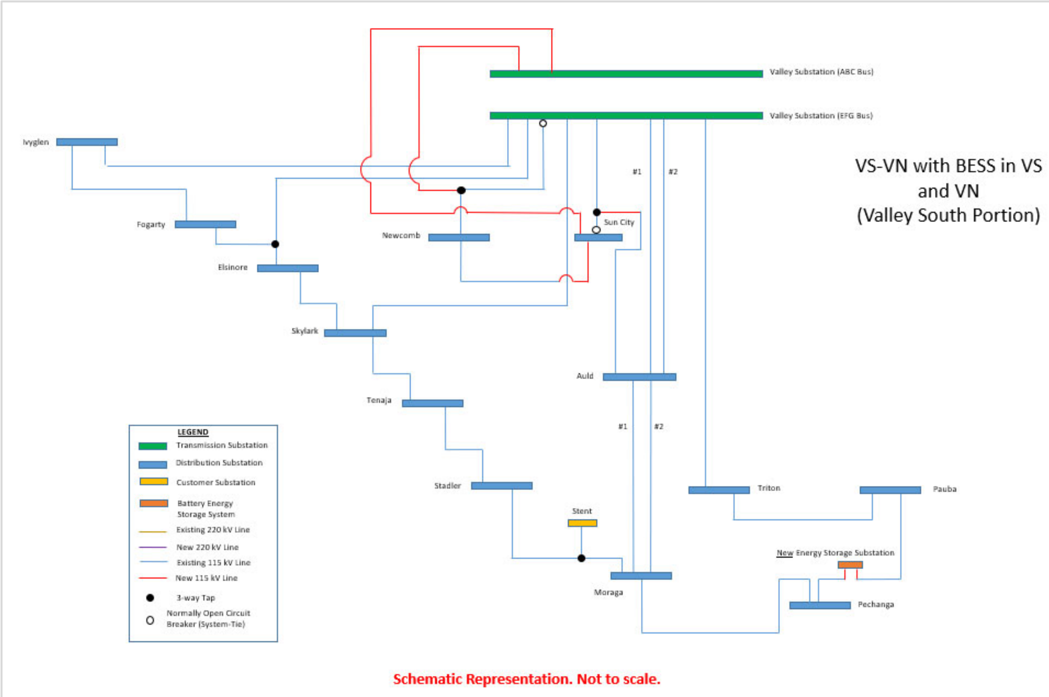
Table 5-90. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	MW	MWh	MW	MWh
2037			83	290
2042 (VS-2043)	39	108	46	335
2046	10	42	18	165
Total Battery Size (including contingency): **196 MW/ 940 MWh**				

Table 5-91. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	MW	MWh	MW	MWh
2040	0	0	67	204
2045	0	0	27	140
Total Battery Size: **94 MW/ 344 MWh**				

Figure 5-13 presents a high-level representation of the proposed configuration.



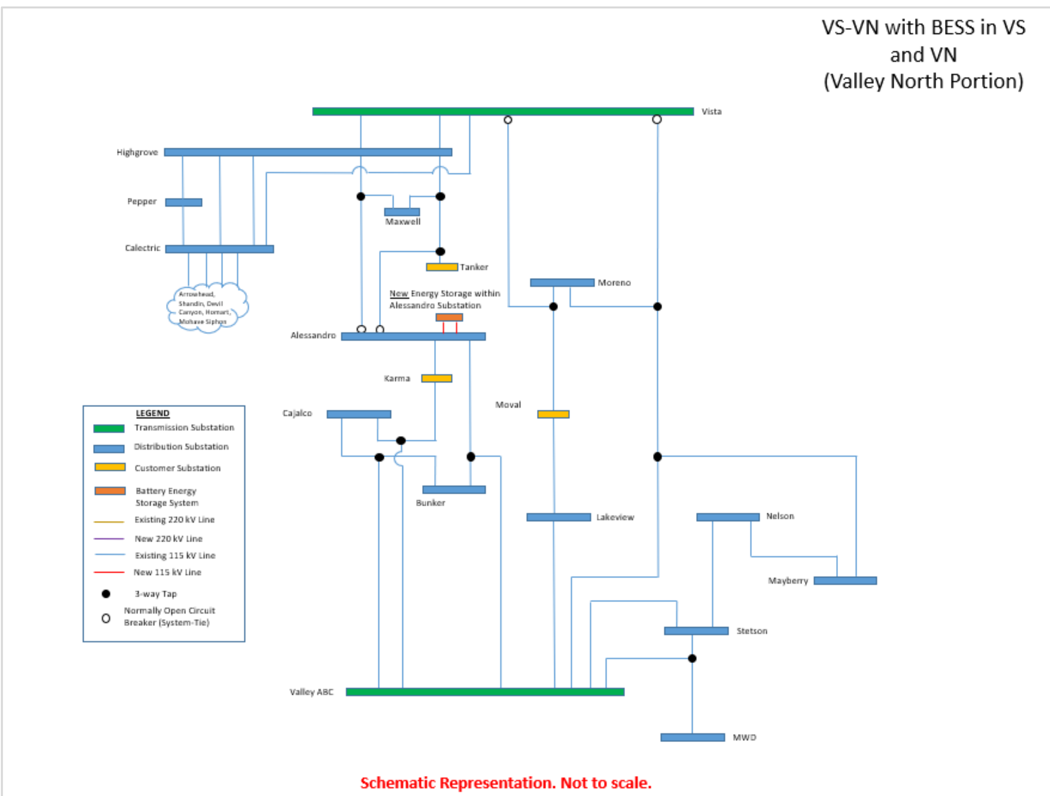


Figure 5-13. Valley South to Valley North and Centralized BESS in Valley South and Valley North

5.3.11.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-92 for the Effective PV Forecast, Table 5-93 for the Spatial Base Forecast, and Table 5-94 for the PVWatts Forecast.

Table 5-92. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	0	0	0	55,858
2043	0	0	0	57,893
2048	0	0	0	59,910

Table 5-93. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	0	0	0	59,306
2043	0	0	0	62,024
2048	0	0	0	64,742

Table 5-94. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	0	0	0	56,399

5.3.11.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-95 for the Effective PV Forecast, Table 5-96 for the Spatial Base Forecast, and Table 5-97 for the PVWatts Forecast.

Table 5-95. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331	127,935	571
2028	0	0	0	64,547	133,688	843
2033	4	2	2	84,028	139,702	1,161
2038	103	14	19	116,572	145,991	1,586
2043	351	24	45	146,858	151,619	2,025
2048	506	27	73	194,760	155,733	2,366

Table 5-96. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,083	129,095	616
2022	0	0	0	25,681	131,322	715
2028	4	3	2	53,273	140,388	1,202
2033	156	19	22	72,267	147,622	1,710
2038	445	23	66	99,260	154,744	2,284
2043	1,063	29	135	122,253	161,142	2,889
2048	1,845	76	205	145,246	166,580	3,429

Table 5-97. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331	127,935	571
2028	0	0	0	46,816	133,688	843
2033	0	0	0	68,054	133,840	850
2038	0.4	0.4	1	89,293	139,065	1,122
2043	47	10	11	110,531	143,845	1,426
2048	138	17	22	131,769	147,226	1,679

In analyzing the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project, the following constraints (Table 5-98) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-98, only thermal violations associated with each constraint are reported.

Table 5-98. List of Valley South to Valley North and Centralized BESS in Valley South and Valley North Project System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2038	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.11.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the project for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 5-99 for the three forecasts.

Table 5-99. Valley South to Valley North and Centralized BESS in Valley South and Valley North Cumulative Benefits

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,322	27,375
N-1	LAR (MWh)	5,724	17,603	62,386
N-1	IP (MW)	366	503	803
N-1	PFD (hr)	1,196	1,456	1,740

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-1	Flex-1 (MWh)	2,795,927	5,140,766.57	11,694,529
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,408	87,739
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project. By design, the project includes a permanent transfer of relatively large load centers in the Valley South System during the initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. The solution completely addresses the N-0 system needs in the Valley South and Valley North Systems.

5.3.11.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided in the near-term and long-term horizon. Additionally, the installation of batteries avoids the N-0 needs in the Valley North System following the transfer of load from the Valley South system. Across all sensitivities, the benefits range from 22.7 to 140.9 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, N-1 benefits in the system range from 5.7 to 59.54 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Should a HILP event occur and impact Valley Substation, the project is unable to serve incremental load in the Valley South System through leveraging the capabilities of its system tie-lines.
5. Overall, the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers a limited advantage in addressing the N-1 and flexibility needs of the system.

5.3.12 Valley South to Valley North to Vista and Centralized BESS in Valley South Project (Project M)

The objective of this project would be to transfer the loads at Newcomb and Sun City Substations to Valley North. The load at Moreno in the Valley North system would be transferred to the Vista system (identical to Project #G). The premise of this methodology is to relieve loading on the Valley North system to accommodate a load transfer from Valley South. Additionally, BESS is installed in Valley South to provide relief over the long-term horizon. This is essentially a combination of Projects G and H. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North System, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.12.1 Description of Project Solution

The proposed project would include the following components:

1. Moreno Substation is transferred to Vista 220/115 kV system through existing system tie-lines between Valley North and Vista Systems.
2. New 115 kV line construction to restore subtransmission network connectivity following a transfer of Moreno Substation.
3. Normally-open circuit breaker at Moreno Substation to provide a system tie-line between the Vista and Valley North Systems.
4. The proposed project would also transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through the construction of new 115 kV lines (see Project F).
5. Normally-open circuit breakers at the Valley South bus and the Sun City Substation are maintained as system ties between the Valley North and Valley South Systems for transfer flexibility.
6. Reconductor existing Auld–Sun City 115 kV line, which would become the Valley–Auld–Sun City 115 kV line.
7. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
8. BESS would be installed near Pechanga Substation following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
9. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-100 and Table 5-101, for all forecasts. No batteries were required at Valley South in the PVWatts Forecast.
10. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026).
11. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

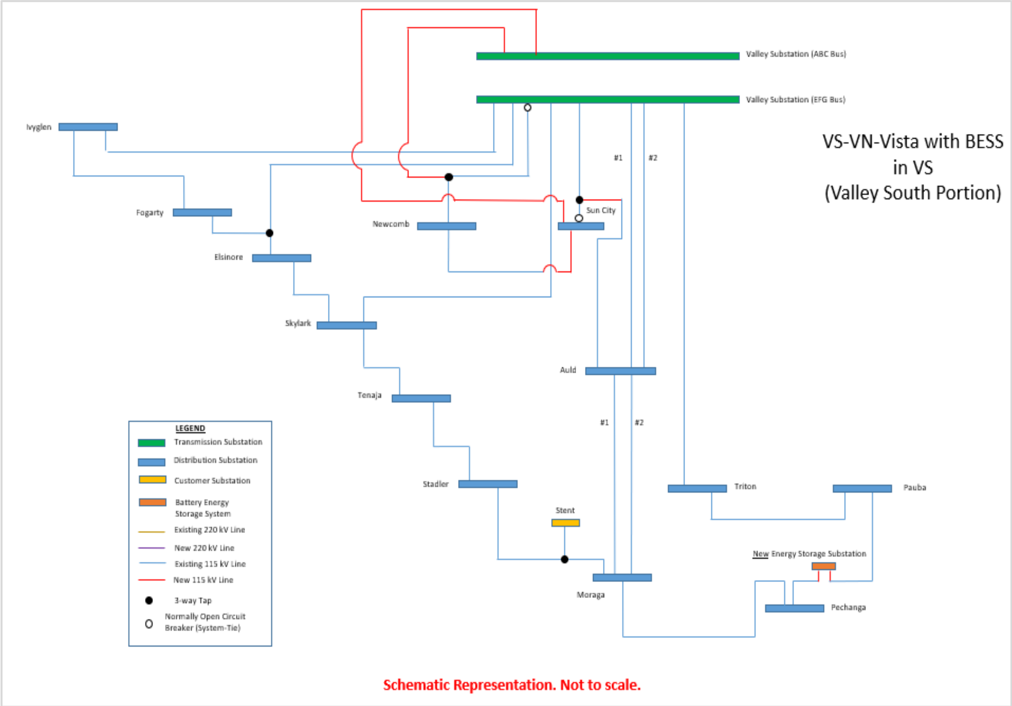
Table 5-100. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2036	81	242
2041	49	291
2046	18	114
Total Battery Size (including contingency): **148 MW / 647 MWh**		

Table 5-101. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2043	39	108
2046	10	42
Total Battery Size (including contingency): **49 MW / 150 MWh**		

Figure 5-14 presents a high-level representation of the proposed configuration.



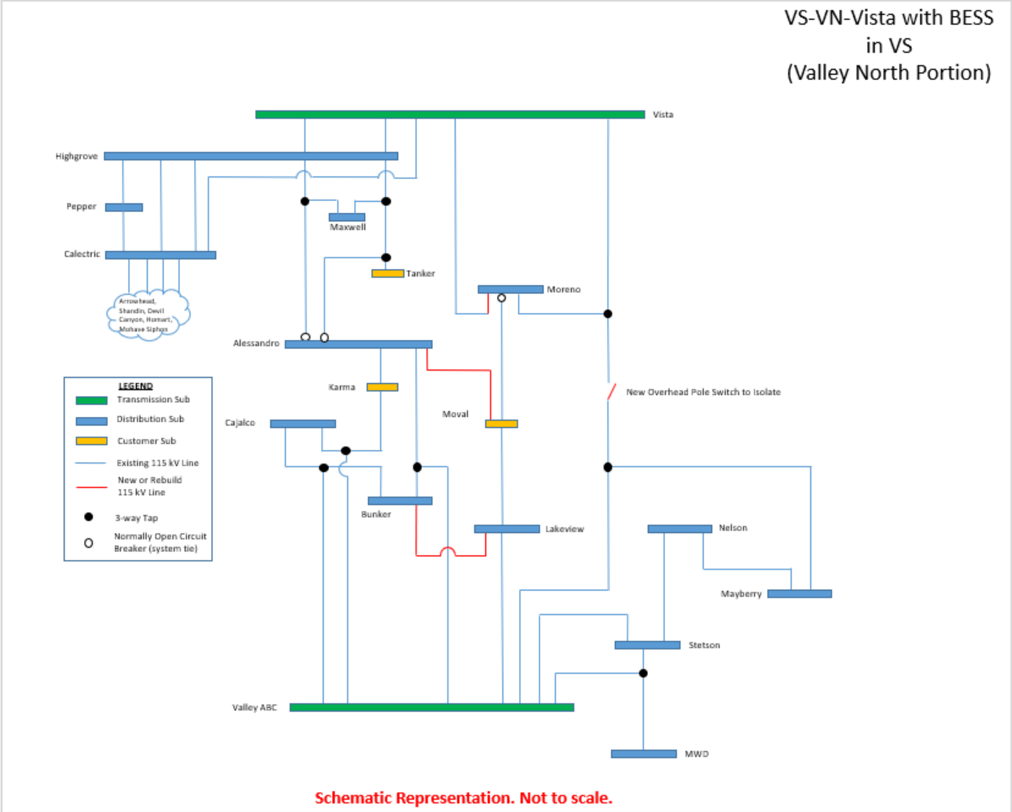


Figure 5-14. Valley South to Valley North to Vista and Centralized BESS in Valley South

5.3.12.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions in the system are presented in Table 5-102 for the Effective PV Forecast, Table 5-103 for the Spatial Base Forecast, and Table 5-104 for the PVWatts Forecast.

Table 5-102. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	0	0	0	55,858
2043	78	30	5	57,893
2048	735	83	18	59,910

Table 5-103. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	676	81	17	59,306
2043	3416	162	58	62,024
2048	8000	232	103	64,742

Table 5-104. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	68	37	5	56,399

5.3.12.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 5-105 for the Effective PV Forecast, Table 5-106 for the Spatial Base Forecast, and Table 5-107 for the PVWatts Forecast.

Table 5-105. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331	127,935	571
2028	0	0	0	64,547	133,688	843
2033	4	2	2	84,028	139,702	1,160
2038	103	14	19	116,572	145,991	1,586
2043	351	24	45	146,858	151,619	2,025
2048	506	27	73	194,760	155,733	2,366

Table 5-106. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,083	129,095	616
2022	0	0	0	25,681	131,322	715
2028	4	3	2	53,273	140,388	1,202
2033	156	19	22	76,267	147,622	1,710
2038	445	23	66	99,260	154,744	2,284
2043	1,063	29	135	122,253	161,142	2,889
2048	1,845	76	205	145,247	166,580	3,429

Table 5-107. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,330	127,935	571
2028	0	0	0	46,816	133,688	843
2033	0	0	0	68,054	133,840	850
2038	0.4	0.4	1	89,292	139,065	1,122
2043	47	10	11	110,530	143,845	1,426
2048	138	17	22	131,768	147,226	1,679

In analyzing the Valley South to Valley North to Vista and Centralized BESS in Valley South Project, the following constraints (Table 5-108) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-108, only thermal violations associated with each constraint are reported.

Table 5-108. List of Valley South to Valley North to Vista and Centralized BESS in Valley South Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2038	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.12.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North to Vista and Centralized BESS in Valley South Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the project for each of the metrics.

The accumulative values of the benefits over the 30-year horizon are presented in Table 5-109 for the three forecasts.

Table 5-109. Valley South to Valley North to Vista and Centralized BESS in Valley South Project Cumulative Benefits

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,322	27,375
N-1	LAR (MWh)	5,724	17,603	62,386
N-1	IP (MW)	366	503	803
N-1	PFD (hr)	1,196	1,456	1,740
N-1	Flex-1 (MWh)	2,795,927	5,140,766.57	11,694,529
N-1	Flex-2-1 (MWh)	-	-	-

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-1	Flex-2-2 (MWh)	59,402	69,408	87,739
N-0	LAR (MWh)	22,613	54,062	96,778
N-0	IP (MW)	2,638	3,687	4,380
N-0	PFD (hr)	399	741	939

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North to Vista and Centralized BESS in Valley South Project. By design, the project includes a permanent transfer of relatively large load centers in the Valley South System during the initial years. This provides significant N-0 system relief in the Valley South System but at the expense of limited operational flexibility. The addition of batteries complements the needs in the Valley South System effectively reducing LAR to zero over the long-term horizon. The transfer of loads from the Valley North System to the Vista System avoid transformer overloads in Valley North until 2041.

5.3.12.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloads on the Valley South System transformers are avoided in the near-term and long-term horizon. Additionally, the transfer of loads from the Valley North System to the Vista System defers the N-0 condition needs in Valley North until 2041. Across all sensitivities, the benefits range between 22.6 to 96.7 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 0.6 to 30.2 GWh through all forecasts.
3. The project provides only limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Should a HILP event occur and impact Valley Substation, the project is unable to serve incremental load in the Valley South System by leveraging capabilities of its tie-lines.
5. Overall, the Valley South to Valley North to Vista and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers a limited advantage in addressing the N-1 and Flexibility needs of the system

5.4 Summary of Findings

Through the analysis of alternatives and applicable reliability metrics, LAR, and flexibility (Flex-1 and Flex-2) provide valuable insight into the reliability, capacity, resilience, and flexibility objectives of project performance. Table 5-110 through Table 5-112 present a summary of these findings across all forecasts.

Table 5-110. Cumulative Benefits: Effective PV Forecast

		Project ID												
Project Name		Alberhill System Project	San Diego Gas & Electric Project	Valley South to Valley North to Vista Project	Centralized BESS in Valley South Project	Mira Loma and Centralized BESS in Valley South Project	Valley South to Valley North and Distributed BESS in Valley South Project	Menifee Project	Mira Loma Project	SCE Orange County Project	Valley South to Valley North and Centralized BESS in Valley South and Valley North Project	Valley South to Valley North to Vista and Centralized BESS in Valley South Project	SDG&E and Centralized BESS in Valley South Project	Valley South to Valley North Project
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	20	21	15	21	21	17	15	15	17	18	18	21	15
N-2	**Available Flex-1**	6,024	5,415	5,357	4,067	3,831	5,742	5,357	3,2554	1,279	5,141	5,141	5,894	5,357
N-2	**Available Flex-2-1**	3,780	3,218	-	-	1,263	-	2,368	1,263	3,256	-	-	3,218	-
N-2	**Available Flex-2-2**	107	77	69	1	65	69	69	65	81	69	69	77	69
N-0	**LAR**	57	56	54	57	57	46	56	50	56	57	54	57	45

Table 5-111. Cumulative Benefits: Spatial Base Forecast

		Project ID												
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	69	76	51	76	76	58	51	45	60	62	62	76	51
N-2	**Available Flex-1**	9,665	9,902	9,662	10,993	9,614	10,977	9,662	6,500	4,209	11,694	11,694	11,526	9,662
N-2	**Available Flex-2-1**	4,102	3,403	-	-	1,327	-	3,030	1,327	3,449	-	-	3,403	-
N-2	**Available Flex-2-2**	142	97	88	5	82	-	88	82	104	88	88	97	88
N-0	**LAR**	141	132	91	141	141	89	136	110	133	141	97	141	41

Table 5-112. Cumulative Benefits: PVWatts Forecast

		Project ID												
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	6	6	6	6	6	6	6	5	5	6	6	6	6
N-2	**Available Flex-1**	4,205	3,363	2,795	2,939	894	2796	2,795	623	584	2,796	2,796	3,440	2,795
N-2	**Available Flex-2-1**	3,658	3,167	-	-	1,252	-	2,860	1,252	3,201	-	-	3,167	-
N-2	**Available Flex-2-2**	88	65	59	1	56	59	59	56	69	59	59	65	59
N-0	**LAR**	23	23	23	23	23	20	23	19	23	23	23	23	20

The following insights are established upon review of the project performance, system benefits, and overall needs in the Valley South System.

1. The Valley South System is vulnerable to the risk of unserved energy starting year 2022 under the Effective PV and PVWatts Forecasts and year 2021 under the Spatial Base Forecast. The Spatial Base Forecast assumes current levels of DER adoption persist through the long-term horizon, whereas the other two forecasts adopt DER consistent with IEPR 2018 forecasts.
2. The unserved energy in the Valley South System continues to grow beyond the 10-year planning horizon. This drives the need for solutions that are capable of supporting long-term load-growth trends in the Valley South System.
3. The load forecast includes the expected levels of peak reduction from DER technologies over the long-term horizon. The amount of relief offered by the expected levels were determined to be insufficient to meet the needs in the Valley South System service territory.
4. Dependency on NWA solutions (e.g., centralized storage) drives large investments and requires periodic upgrades to keep pace with the load-growth trend in the system. Although these solutions provide N-0 and N-1 relief, they offer limited flexibility to support planned, unplanned or emergency operations in the system (including N-2 outages and HILP events).
5. Dependency on neighboring systems (Valley North and Mira Loma) provides limited relief in terms of N-0 and N-1 benefits. While some solutions address the needs in the Valley South System, they aggravate the condition in the adjacent subtransmission system. For example, with a transfer of loads to Valley North, the risk of transformer overload significantly increases in the Valley North service territory. Additional transfers from Valley North to its neighbors provide limited relief over a long-term horizon. These solutions are also restricted by the capabilities of the neighboring system during peak loading conditions.
6. A combination of storage and tie-lines to neighboring systems provide improved benefits in comparison to stand-alone NWAs. These benefits are realized because tie-lines can be leveraged in combination with local storage capacity. However, these solutions were found to require large investments, while only contributing to N-0 objectives in the system. Although they offer improved flexibility and N-1 benefits, they are not sufficient to adequately meet all the needs in Valley South.
7. Wire-based alternatives offer the highest relief to meet the needs in the Valley South System. These solutions were found to adequately meet the range of forecast sensitivities while meeting the overall project objectives. Except for the projects that did not meet the objectives over the study horizon and those with significant implementation difficulty, wire-based alternatives offer the highest benefits.
8. In all considered forecasts, the ASP provided the highest aggregated benefits. Aggregated benefits are derived from the cumulative value of LAR and Flex Metrics that translate into capacity, reliability, resilience, and flexibility needs in the Valley South service area. The ASP consistently provides the highest aggregated benefits across all considered forecasts.
9. From a capacity perspective, the ASP, SDG&E, and Hybrid solutions (SDG&E and Centralized BESS in Valley South) provide the most relief. Taking into consideration the combination of flexibility and resilience needs, the ASP, Orange County Project, and SDG&E Project are the most preferable alternatives.

6 BENEFIT-COST ANALYSIS (BCA)

6.1 Introduction

The objective of this task was to perform a detailed benefit-cost and risk analysis of the ASP and alternative projects introduced in Section 5. This framework provides an additional basis for the comparison of project performance while justifying the business case of each alternative in meeting the load growth and reliability needs of the Valley South System.

The benefit is defined as the value of the impact of a project on a firm, a household, or society in general. This value can be either monetized or treated on a unit basis while dealing with reliability metrics like LAR, Interrupted Power, and Period of Flexibility Deficit among other considerations. Net benefits are the total reductions in costs and damages as compared to the baseline, accruing to firms, customers, and society at large, excluding transfer payments between these beneficiary groups. All future benefits and costs are reduced to a present worth (NPV) using a discount rate, and an inflation rate, over the project lifetime.

Following the quantification of the present worth of costs and benefits (Sections 4 and 5), three different types of analysis have been considered to provide a comprehensive view of the value attributed to each project. These are traditional BCA, $/unit benefit analysis, and incremental BCA. These analyses use non-monetized and monetized benefits consistent with the methodology described in Section 3.3 over the 30-year study horizon.

6.2 Benefit-Cost Calculation Spreadsheet

All the findings within this section are maintained in a spreadsheet outlining the calculations and associated costs. Hence, three spreadsheets[11] are provided that cover three study forecasts (Spatial Base, Effective PV, and PVWatts). These spreadsheets are provided with this submission.

The key elements within the spreadsheet are addressed in individual tabs are briefly introduced.

- Summary
  - Summarizes the study results and findings.
- Incremental Benefit-Cost Analysis
  - Results and rankings from the incremental benefit-cost analysis.
- Cost Assumptions
  - Outlines the key study inputs and assumptions.
- Baseline System Analysis
  - Raw reliability Indices.
  - The monetized value of the baseline reliability metrics.

[11] The three Excel spreadsheets are attached to this report.

Each spreadsheet address the following information as an individual tab for each alternative project.

- Benefit-cost Quantification to Baseline System
    - Raw reliability indices.
    - The monetized value of project reliability metrics.
    - Comparison of each project against baseline system performance.

6.3 Results from Benefit-Cost Analysis

The benefit-cost analysis is performed for all three forecasts under consideration, consistent with the methodology described in Section 3.3, and the study results for the following 13 alternative projects are present.

A. Alberhill System
B. San Diego Gas & Electric
C. SCE Orange County
D. Menifee
E. Mira Loma
F. Valley South to Valley North
G. Valley South to Valley North to Vista
H. Centralized BESS in Valley South
I. Valley South to Valley North and Distributed BESS in Valley South
J. SDG&E and Centralized BESS in Valley South
K. Mira Loma and Centralized BESS in Valley South
L. Valley South to Valley North and Centralized BESS in Valley South and Valley North
M. Valley South to Valley North to Vista and Centralized BESS in Valley South

6.3.1 Projects' Cost

The cost for each project is provided by SCE, in the PVRR and Aggregated (Total Capital Expenditure) representation. The PVRR costs include the investment costs and project expenses and calculated using the applicable discount rate. The cost of components associated with the design of projects is aggregated to develop the Total capital expenditure. For projects that include BESS, the PVRR costs are offset by revenues generated from market participation. Information regarding the scope of the projects has been summarized in Sections 4 and 5.

Table 6-1 provides the present worth and aggregated costs associated with each project. For BESS-based solutions, the cost varies as a function of the forecast under study. Table 6-2 provides the present worth of market participation revenues for the BESS-based solution.

Table 6-1. Project Cost (PVRR and Capex)

#	Project	Effective PV Forecast		Spatial Base		PVWatts	
		Present Worth ($M)	Aggregated ($M)	Present Worth ($M)	Aggregated ($M)	Present Worth ($M)	Aggregated ($M)
A	Alberhill System Project	$474	$545	$474	$545	$474	$545
B	SDG&E	$453	$540	$453	$540	$453	$540
C	SCE Orange County	$748	$951	$748	$951	$748	$951
D	Menifee	$331	$396	$331	$396	$331	$396
E	Mira Loma	$309	$369	$309	$365	$309	$365
F	Valley South to Valley North	$207	$221	$207	$221	$207	$221
G	Valley South to Valley North to Vista	$290	$317	$290	$317	$309	$365
H	Centralized BESS in Valley South	$525	$1,474	$848	$2,363	$381	$1,004
I	Valley South to Valley North and Distributed BESS in Valley South	$232	$326	$228	$354	$200	$218
J	SDG&E and Centralized BESS in Valley South	$531	$923	$658	$1,473	$479	$685
K	Mira Loma and Centralized BESS in Valley South	$560	$1,396	$601	$2,194	$448	$920
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	$1,172	$700	$2,616	$255	$572
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	$505	$404	$986	$269	$307

Table 6-2. Present Worth of Market Participation Revenues

Wholesale Energy and Ancillary Service markets				
#	Project	Effective PV Forecast Present Worth of Market Participation Revenue ($M)	Spatial Base Present Worth of Market Participation Revenue ($M)	PVWatts Present Worth of Market Participation Revenue ($M)
H	Centralized BESS in Valley South	$70	$109	$47
I	Valley South to Valley North and Distributed BESS in Valley South	$2	$5	-
J	SDG&E and Centralized BESS in Valley South	$5	$19	-
K	Mira Loma and Centralized BESS in Valley South	$25	$57	$8
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$12	$57	$4
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2	$11	-

Capacity and Resource Adequacy Markets				
#	Project	Effective PV Forecast Present Worth of Market Participation Revenue ($M)	Spatial Base Present Worth of Market Participation Revenue ($M)	PVWatts Present Worth of Market Participation Revenue ($M)
H	Centralized BESS in Valley South	$48,515	$74,932	$34,058
I	Valley South to Valley North and Distributed BESS in Valley South	$863	$2,105	-
J	SDG&E and Centralized BESS in Valley South	$3,579	$13,712	-
K	Mira Loma and Centralized BESS in Valley South	$18,124	$36,287	$6,395
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$10,185	$37,148	$2,798
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,000	$7,841	-

6.3.2 Baseline System Analysis

From the baseline system, the raw reliability indices computed in Section 4.2 are reflective of the overall impact on customers in the Valley South service territory. The monetization of EENS and Flexibility benefits demonstrate the aggregated cost impact to customers in the region. All benefits have been monetized consistent with the methodology outlined in Section 3.3 and derived as present worth. Table 6-3 presents the aggregated costs, taking into consideration the combination of Residential, Small & Medium Business and Commercial & Industrial customers.

Table 6-3. Baseline System Monetization

Category	Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Monetized Value for EENS - N-1	126,010	428,178	35,200
Monetized Value for EENS - – N-0	2,530,518,587	5,999,276,476	1,029,268,277
Monetized Value for Flex-1	6,191,361	9,670,328	4,309,495
Monetized Value for Flex-2 ($)	1,765,322,893	1,816,115,205	1,722,124,246
Aggregate ($M)	**4,302**	**7,825**	**2,756**

The results demonstrate that the aggregated range of cost impacts accrued by the customer range from 2.7$B to 7.8$B over the horizon of forecast uncertainties captured by this analysis. Projects that effectively reduce the customer costs in all benefit categories are most suitable to address the growing needs in the Valley South System.

6.3.3 Benefit-Cost Analysis

The ratio of benefit-cost has been derived across the long-term study horizon. The costs are adopted from Table 6-1 and the monetized benefits are derived using the methodology in Section 3.3. Only relevant benefit categories have been monetized where the energy unserved component is calculated, including EENS, Flex-1, Losses, and Flex-2.

Table 6-4 to Table 6-6 exhibit the benefit-to-cost ratio for the 13 alternatives under three forecasts, wherein alternatives can be ranked against the benefit to cost ratio.

Table 6-4. SCE Effective PV Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$3,882	11.73
F	Valley South to Valley North	$2,156	10.41
I	Valley South to Valley North and Distributed BESS in Valley South	$2,165	9.33
A	Alberhill System Project	$4,282	9.03
B	SDG&E	$4,001	8.84
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2,479	8.58
G	Valley South to Valley North to Vista	$2,470	8.52
E	Mira Loma	$2,601	8.42
J	SDG&E and Centralized BESS in Valley South	$4,041	7.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$2,542	6.93
K	Mira Loma and Centralized BESS in Valley South	$3,132	5.59
C	SCE Orange County	$4,021	5.38
H	Centralized BESS in Valley South	$2,535	4.83

Table 6-5. SCE Spatial Base Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$7,201	21.76
A	Alberhill System Project	$7,788	16.43
B	SDG&E	$7,218	15.93
G	Valley South to Valley North to Vista	$4,617	15.92
E	Mira Loma	$4,766	15.42
F	Valley South to Valley North	$2,618	12.65
I	Valley South to Valley North and Distributed BESS in Valley South	$2,736	12.00
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$4,771	11.81
J	SDG&E and Centralized BESS in Valley South	$7,523	11.43
K	Mira Loma and Centralized BESS in Valley South	$6,604	10.99
C	SCE Orange County	$7,258	9.70
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$6,016	8.59
H	Centralized BESS in Valley South	$6,008	7.08

Table 6-6. PVWatts Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$2,381	7.19
A	Alberhill System Project	$2,740	5.78
B	SDG&E	$2,520	5.56
J	SDG&E and Centralized BESS in Valley South	$2,520	5.26
E	Mira Loma	$1,512	4.89
I	Valley South to Valley North and Distributed BESS in Valley South	$955	4.77
F	Valley South to Valley North	$955	4.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$1,039	4.07
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,036	3.85
K	Mira Loma and Centralized BESS in Valley South	$1,625	3.63
G	Valley South to Valley North to Vista	$1,036	3.57
C	SCE Orange County	$2,533	3.39
H	Centralized BESS in Valley South	$1,032	2.71

As Table 6-4 demonstrates, for the effective PV forecast the Menifee project renders the largest benefit to cost ratio of 11.02. Although the Menifee project has the largest benefit to cost ratio, its cost of $331M is 60% higher than the least expensive project, i.e. Valley South to Valley North with a cost of $207M (Table 6-1). However, the benefit-to-cost ratio of the Valley South to Valley North is 10.41, which is 6% higher. In other words, the additional 40% cost of the Menifee project as compared to the Valley South to Valley North project renders 6% of additional benefit. The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. While it provides an indication of each project's performance, it does not adequately provide a measure to compare alternatives.

The best project among a set of alternative projects is not necessarily the one that maximizes the benefit-to-cost ratio. The benefit-to-cost analysis is a measure consider in the determination to reject or approve a project. But when it comes to the selection among alternatives and the process of reliability improvement projects, an incremental benefit-cost analysis should be conducted. The incremental benefit-to-cost analysis methodology is based on the principle of spending each dollar funding the project that will result in the most benefit, resulting in an optimal budget allocation that identifies the projects that should be funded [10].

To conduct a correct selection among alternative projects with widely disparate benefits an incremental analysis approach to evaluating benefits and costs is necessary [9]. This approach is presented in Section 6.3.4.

6.3.4 Incremental Benefit-Cost Analysis

As described earlier, the incremental analysis starts with ranking alternatives in the ascending order of the present worth of costs. The do-nothing with zero cost is then selected as the baseline, i.e. alternative "0". The next expensive project is then considered, and the incremental benefit-to-cost analysis is then conducted to determine if such a selection should be made or not. The incremental benefit to cost ratio between the baseline and the next expensive alternative is evaluated, which in this case is alternative "F", i.e. Valley South to Valley North. Alternative "F" versus baseline incremental benefit-cost ratio was evaluated using the present worth of monetized benefits versus PVRR costs.

In general, a project is selected if the incremental benefits exceed its incremental cost. This approach can be conducted for non-monetized and monetized benefits. The non-monetized selection is qualitative and subjective as the selection is based on individual indices performance. The monetized analysis is solely based on a single incremental benefit-to-cost ratio. Both non-monetized and monetized incremental cost-benefit analyses are depicted in the following tables. As the selection under non-monetized analysis is subjective, the results are presented for demonstration only.

For monetized incremental cost-benefit analysis, if the incremental ratio is larger than unity the next expensive project "F" is selected. Once a selection is made, the selected alternative replaces the baseline. This selection is demonstrated as "0→F" in Table 6-8. The process continues through the list of alternative projects, which are ranked in ascending cost order until the list is exhausted.

At the next step, the second least expensive project, i.e. "I" is compared to the baseline project "F". Project "I" was not selected as the incremental benefit-to-cost ratio is less than unity, and hence "F" remains as the baseline project. The incremental benefit-cost analysis will continue by iterating between the baseline and the next expensive alternative. The selection will stop once the incremental benefit-cost ratio becomes unfavorable or the list is exhausted. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as environmental impact and risks. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as environmental impact and risks.

For monetized benefits, the criteria to move forward to the next expensive project is considered as a positive (total) aggregated value greater than unity. As one moves along the trajectory of the least cost solutions, the more positive numbers are indicative of improved monetized benefits in each of the categories. If the next expensive alternative presents more favorable returns, and a decision to stop at the previous solution is made, it is representative of benefits that are available but not realized.

The incremental benefit-cost analysis of the monetized benefits is presented in Table 6-8, Table 6-10**,** and Table 6-12 for the Effective PV, Spatial Base, and PVWatts forecasts respectively.

The incremental benefit-cost analysis of non-monetized benefits is presented in Table 6-7, Table 6-9, and Table 6-11 for the Effective PV, Spatial Base, and PVWatts forecasts respectively. The selections were conducted qualitatively and are presented for reference only.

Table 6-7. Non-Monetized Benefits – Incremental Benefit-Cost Analysis – Effective PV Forecast

Category		Alternative selection												
		0 → F	F → I	I→ M	I → G	I → E	I →D	I → L	I → B	B → A	A → H	A → J	A → K	A → C
N-1	LAR	-11.27	-6.50	-0.94	2.80	2.73	1.64	-0.42	-2.32	5.23	-2.20	-1.97	-1.22	1.61
N-1	IP	-0.54	-0.28	0.04	0.12	0.17	0.07	0.02	-0.16	0.97	-0.41	-0.36	-0.22	0.10
N-1	PFD	-1.58	-1.07	-0.16	0.46	0.44	0.27	-0.07	-0.35	0.49	-0.21	-0.19	-0.08	0.08
N-1	Available Flex-1	-5,893.06	-3,339.83	2,223.74	1,439.58	7,537.63	843.39	938.91	317.75	-9,549.32	10,147.65	1,604.86	6,728.74	4,329.79
N-1	Available Flex-2-1	0.00	0.00	0.00	0.00	-5,555.36	-9,860.00	0.00	-4,889.92	-7,682.16	24,377.09	2,889.84	9,482.20	560.54
N-1	Available Flex-2-2	-95.59	-0.02	0.00	0.01	15.28	0.01	0.00	-9.02	-346.00	566.20	130.16	123.05	22.44
N-0	LAR	-36.29	-1.28	-15.50	-14.69	3.84	-10.93	-8.24	-4.59	-4.67	-0.01	-0.01	-0.01	0.36
N-0	IP	-3.70	-0.74	-0.57	-0.38	2.44	-0.58	-0.51	-0.16	-1.55	-0.01	-0.01	0.00	0.12
N-0	PFD	-0.57	-0.10	-0.35	-0.31	0.12	-0.26	-0.20	-0.10	-0.18	-0.01	-0.01	0.00	0.01
Decision to move forward (Y/N)		Y	Y	N	N	N	N	N	Y	Y	N	N	N	N

Table 6-8. Monetized Benefits – Incremental Benefit-Cost Analysis – Effective PV Forecast

Category		Alternative selection												
		0 → F	F → I	F → M	M → G	M → E	E →D	D → L	D → B	B → A	A → H	A → J	A → K	A → C
N-0	EENS	10.356	0.373	3.948	-9.313	-23.358	23.629	0.290	-0.235	1.812	0.003	0.003	0.002	-0.123
N-0	Losses	0.001	0.000	0.000	-0.001	0.018	-0.007	-0.006	0.023	0.055	-0.073	-0.021	-0.045	-0.005
N-1	EENS	0.000	0.000	0.000	-0.009	-0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
N-1	Flexibility-1	0.020	0.009	0.000	0.026	-0.107	0.098	-0.001	-0.008	0.105	-0.044	-0.030	-0.036	-0.016
N-1	Flexibility-2-1	0.000	0.000	0.000	0.000	29.576	34.485	-37.505	1.191	10.992	-33.935	-4.135	-13.246	-0.802
N-1	Flexibility-2-2	0.036	0.000	0.000	0.000	-0.022	0.020	0.000	0.006	0.136	-0.217	-0.051	-0.048	-0.009
Total	Sum of ΔB/ΔC (aggregate)	10.413	0.382	3.947	-9.297	6.087	58.233	-37.216	0.954	13.044	-34.192	-4.213	-13.329	-0.949
Decision to move forward (Y/N)		Y	N	Y	Y	Y	Y	N	Y	Y	N	N	N	N

Table 6-9. Non-Monetized Benefits – Incremental Benefit-Cost Analysis – Spatial Base Forecast

Category		Alternative selection												
		0 → F	F→ I	I → G	I →E	I → D	I → M	M → B	B → A	A→ K	A→ J	A→ L	A→ C	A→ H
N-1	LAR	-33.49	-37.60	12.74	17.76	6.87	-2.55	-33.16	31.64	-5.17	-3.91	4.25	4.87	-1.91
N-1	IP	-0.75	-0.86	0.29	0.28	0.18	-0.03	-1.66	2.46	-0.41	-0.32	0.13	0.23	-0.15
N-1	PFD	-2.16	-0.13	0.04	1.72	0.03	-0.20	-4.41	1.04	0.04	-0.14	0.86	0.22	-0.06
N-1	Available Flex-1	-9,712.04	-12,207.92	4,134.94	11,626.02	2,488.99	-799.25	7,106.92	-1,615.54	1,112.01	-1,621.04	-1,390.76	4,664.64	-419.28
N-1	Available Flex-2-1	0.00	0.00	0.00	-5,369.71	-9,643.82	0.00	-22,563.56	-9,103.32	6,786.12	1,038.97	5,737.98	650.75	3,467.34
N-1	Available Flex-2-2	-113.44	-4.86	1.65	18.85	0.99	0.50	-50.26	-485.96	110.90	55.44	56.05	31.36	94.63
N-0	LAR	-50.38	-18.14	-88.77	-60.88	-96.09	-33.99	-71.33	-41.13	-0.27	-0.19	-0.15	2.84	-0.09
N-0	IP	-4.06	-3.03	-1.72	1.87	-3.25	-1.20	-1.36	-7.01	-0.06	-0.04	-0.03	0.52	-0.02
N-0	PFD	-0.59	-0.22	-1.18	-0.77	-1.43	-0.49	-1.08	-0.62	-0.05	-0.03	-0.03	0.04	-0.02
Decision to move forward (Y/N)		Y	Y	Y	N	N	N	Y	Y	Y	N	N	N	N

Table 6-10. Monetized Benefits – Incremental Benefit-Cost Analysis – Spatial Base Forecast

Category		Alternative selection												
		0 → F	F→ I	I → G	G→E	E → D	D → M	D → B	B → A	A→ K	A→ J	A→ L	A→ C	A→ H
N-0	**EENS**	12.57	5.62	30.35	-23.03	76.11	-14.85	-1.16	13.86	0.10	0.07	0.05	-0.97	0.03
N-0	**Losses**	0.00	0.00	0.00	0.02	-0.01	0.00	0.03	0.08	-0.04	-0.01	-0.02	-0.01	-0.01
N-1	**EENS**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-1	**Flexibility-1**	0.03	0.03	-0.01	-0.17	0.14	0.01	-0.01	0.12	-0.02	-0.01	0.00	-0.02	0.00
N-1	**Flexibility-2-1**	0.00	0.00	0.00	31.04	34.42	-18.45	1.28	12.89	-9.32	-1.47	-7.85	-0.92	-4.74
N-1	**Flexibility-2-2**	0.04	0.00	0.00	-0.03	0.02	0.00	0.01	0.19	-0.04	-0.02	-0.02	-0.01	-0.04
Total	**Sum of ΔB/ΔC (aggregate)**	12.64	5.65	30.34	7.81	110.69	-33.29	0.11	27.07	-9.28	-1.43	-7.82	-1.93	-4.75
Decision to move forward (Y/N)		Y	Y	Y	Y	Y	Y	Y	Y	N	Y	Y	N	N

Table 6-11. Non-Monetized Benefits – Incremental Benefit-Cost Analysis – PVWatts Forecast

Category		Alternative selection												
		0 → I	I → F	I → L	L →M	L→ G	L → E	L→ D	L → H	L → K	L→ B	B → A	A → J	A → C
N-1	LAR	-4.72	0.00	0.00	0.00	0.00	0.51	0.00	-0.52	-0.34	-0.33	0.40	-1.69	0.59
N-1	IP	-0.45	0.00	0.00	0.00	0.00	0.03	0.00	-0.09	-0.06	-0.05	0.17	-0.71	0.06
N-1	PFD	-1.51	0.00	0.00	0.00	0.00	0.12	0.00	-0.10	-0.07	-0.07	0.09	-0.37	0.15
N-1	Available Flex-1	-3,475.85	29.81	0.00	0.00	5.89	9,466.51	2.75	-78.96	2,261.87	-594.68	-11,884.27	43,746.18	3,460.14
N-1	Available Flex-2-1	0.00	0.00	0.00	0.00	0.00	-7,882.61	-12,775.72	0.00	-2,205.50	-5,394.24	-7,225.14	30,345.58	516.40
N-1	Available Flex-2-2	-89.61	0.00	0.00	0.00	0.00	19.50	0.00	141.18	5.46	-8.89	-287.42	1,207.16	18.02
N-0	LAR	-17.11	0.00	-4.37	0.81	0.32	6.52	0.00	0.00	0.00	0.00	-0.01	0.00	0.00
N-0	IP	-2.64	0.00	-1.38	0.44	0.17	2.03	0.00	0.00	0.00	0.00	-0.01	0.00	0.00
N-0	PFD	-0.37	0.00	-0.15	0.07	0.03	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	N	N	N	N	Y	Y	N

Table 6-12. Monetized Benefits – Incremental Benefit-Cost Analysis – PVWatts Forecast

Category		Alternative selection												
		0 → I	I → F	I → L	L → M	L→ G	L → E	E → D	D → H	D → K	D → B	B → A	A → J	A → C
N-0	EENS	4.73	0.00	1.53	-0.19	-0.08	-2.09	5.14	0.00	0.00	0.00	0.00	0.00	0.00
N-0	Losses	0.00	0.00	0.00	0.00	0.00	0.01	-0.01	0.00	0.00	0.02	0.06	-0.28	0.00
N-1	EENS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-1	Flexibility-1	0.01	0.00	0.00	0.00	0.00	-0.04	0.10	-0.02	-0.02	0.00	0.09	-0.35	-0.01
N-1	Flexibility-2-1	0.00	0.00	0.00	0.00	0.00	10.89	34.26	-26.84	-6.44	1.12	10.19	-42.82	-0.73
N-1	Flexibility-2-2	0.03	0.00	0.00	0.00	0.00	-0.01	0.02	-0.13	0.00	0.01	0.11	-0.46	-0.01
Total	Sum of ΔB/ΔC (aggregate)	4.77	0.00	1.53	-0.19	-0.08	8.74	39.52	-26.98	-6.46	1.12	10.39	-43.63	-0.75
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	Y	Y	N	N	Y	Y	N

6.3.5 Levelized Cost Analysis ($/Unit Benefit)

Table 6-13 to Table 6-15 presents the $/Unit Benefit obtained for each alternative under evaluation. The Levelized cost/benefit ratio for each reliability index (LAR through PFD) is calculated for each alternative. For example, in Table 6-13, 0.16 as listed under column A and row N-1 LAR is the ratio of Alberhill project $474 M (Table 6-1) net present cost to present worth of N-1 LAR over study horizon of 2,896 MWh.

A smaller N-1 LAR value implies a more cost-effective solution. Along each row, the ratios are ranked using heat-mapping, with green and red marking the most favorable and the most unfavorable ends of the spectrum. The rightmost three columns, Alternative Rankings, identifies the first three projects per reliability index. The table bottom row, Count of Rank #1, provides the frequency that an alternative ranked first.

Table 6-13. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

Effective PV Forecast

		Alberhill System Project	SDG&E	Valley South to Valley North to Vista	Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	Menifee	Mira Loma	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.16	0.15	0.12	0.17	0.19	0.09	0.14	0.14	0.30	0.14	0.11	0.18	0.09	F	I	M
N-1	IP ↓	3.57	2.94	2.62	3.42	3.70	1.97	2.99	2.95	7.12	3.17	2.50	3.45	1.87	F	I	M
N-1	PFD ↓	1.13	1.05	0.88	1.22	1.31	0.65	1.01	0.96	1.88	1.01	0.79	1.23	0.63	F	I	M
N-1	Flex-1↓	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	F	I	G
N-1	Flex-2-1↓	3.81E-04	4.20E-04			1.31E-03		4.09E-04	7.22E-04	6.86E-04			4.92E-04		A	D	B
N-1	Flex-2-2↓	1.62E-02	2.08E-02	1.47E-02	1.65E+00	3.02E-02	1.17E-02	1.68E-02	1.67E-02	3.25E-02	1.86E-02	1.46E-02	2.44E-02	1.05E-02	F	I	M
N-0	LAR ↓	0.05	0.05	0.03	0.06	0.06	0.03	0.04	0.04	0.09	0.04	0.03	0.06	0.03	F	I	M
N-0	IP ↓	0.56	0.55	0.36	0.62	0.66	0.30	0.39	0.52	0.91	0.43	0.35	0.62	0.27	F	I	M
N-0	PFD ↓	3.24	3.17	2.10	3.58	3.81	1.93	2.28	2.78	5.24	2.50	2.07	3.62	1.76	F	I	M
Count of Rank #1		1	0	0	0	0	0	0	0	0	0	0	0	8			

Table 6-14. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

Spatial Base Forecast

		Alberhill System Project	SDG&E	Valley South to Valley North to Vista	Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	Menifee	Mira Loma	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**	**#1**	**#2**	**#3**
N-1	**LAR ↓**	0.05	0.05	0.04	0.09	0.06	0.03	0.05	0.05	0.10	0.09	0.05	0.07	0.03	I	F	G
N-1	**IP ↓**	2.28	1.75	1.86	3.21	2.32	1.31	2.13	1.99	5.16	3.93	2.27	2.47	1.33	I	F	B
N-1	**PFD ↓**	0.70	0.65	0.65	1.21	0.89	0.51	0.74	0.69	1.21	1.44	0.83	0.94	0.46	F	I	B
N-1	**Flex-1↓**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	F	G	A
N-1	**Flex-2-1↓**	3.66E-04	4.10E-04			1.38E-03		3.33E-04	3.11E-04	6.69E-04			5.95E-04		E	D	A
N-1	**Flex-2-2↓**	1.31E-02	1.74E-02	1.23E-02	1.10E+00	2.72E-02	9.67E-03	1.41E-02	1.32E-02	2.71E-02	2.98E-02	1.72E-02	2.53E-02	8.81E-03	F	I	G
N-0	**LAR ↓**	0.02	0.02	0.02	0.04	0.03	0.02	0.02	0.01	0.04	0.03	0.02	0.03	0.02	E	D	G
N-0	**IP ↓**	0.36	0.38	0.29	0.63	0.45	0.25	0.27	0.25	0.63	0.52	0.36	0.49	0.25	F	E	I
N-0	**PFD ↓**	1.70	1.71	1.45	2.98	2.11	1.80	1.21	1.13	2.80	2.46	1.90	2.31	1.70	E	D	G
Count of Rank #1		0	0	0	0	0	2	0	3	0	0	0	0	4			

Table 6-15. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

PVWatts Forecast

		Alberhill System Project	SDG&E	Valley South to Valley North to Vista	Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	Menifee	Mira Loma	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.47	0.45	0.31	0.38	0.44	0.21	0.35	0.34	0.89	0.27	0.29	0.47	0.22	I	F	L
N-1	IP ↓	4.91	4.52	3.25	3.80	4.47	2.24	3.70	3.51	9.37	2.85	3.01	4.78	2.31	I	F	L
N-1	PFD ↓	1.51	1.43	0.96	1.21	1.42	0.66	1.09	1.04	2.75	0.84	0.89	1.52	0.68	I	F	L
N-1	Flex-1↓	0.0005	0.0006	0.0004	0.0006	0.0014	0.0003	0.0005	0.0017	0.0065	0.0004	0.0004	0.0006	0.0003	I	F	L
N-1	Flex-2-1↓	3.89E-04	4.24E-04			1.05E-03		3.41E-04	7.26E-04	6.94E-04			4.48E-04		D	A	B
N-1	Flex-2-2↓	1.84E-02	2.30E-02	1.72E-02	2.87E+00	2.66E-02	1.12E-02	1.85E-02	1.83E-02	3.60E-02	1.42E-02	1.50E-02	2.43E-02	1.16E-02	I	F	L
N-0	LAR ↓	0.13	0.12	0.08	0.10	0.12	0.06	0.09	0.10	0.20	0.07	0.07	0.13	0.06	I	F	L
N-0	IP ↓	0.79	0.75	0.49	0.63	0.74	0.38	0.55	0.55	1.24	0.42	0.45	0.79	0.39	I	F	L
N-0	PFD ↓	5.78	5.53	3.59	4.65	5.46	2.71	4.04	4.04	9.12	3.11	3.32	5.84	2.80	I	F	L
Count of Rank #1		0	0	0	0	0	8	1	0	0	0	0	0	0			

6.4 Risk Analysis

The risk analysis performed within this assessment is deterministic. As stated earlier, three forecast sensitivities were considered: Effective PV, Spatial Base, and PVWatts forecasts. The Effective PV forecast closely matches the expected load growth in the Valley South region. The Spatial Base and PVWatts forecasts are located above and below the Effective PV and thus were used as upper and lower bounds of uncertainty that characterize variability in the adoption of DER, impacts of electrification, and overall impacts of load reducing technologies.

Table 6-16 presents a comparison of the benefit-cost ratios as they vary with different forecasts.

Table 6-16. Deterministic Risk Assessment

Project	Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Alberhill System Project	9.03	16.43	5.78
SDG&E	8.84	15.93	5.56
Valley South to Valley North to Vista	8.52	15.92	3.57
Centralized BESS in Valley South	4.83	7.08	2.71
Mira Loma and Centralized BESS in Valley South	5.59	10.99	3.63
Valley South to Valley North and Distributed BESS in Valley South	9.33	12.00	4.77
Menifee	11. 73	21.76	7.19
Mira Loma	8.42	15.42	4.89
SCE Orange County	5.38	9.70	3.39
Valley South to Valley North and Centralized BESS in Valley South and Valley North	6.93	8.59	4.07
Valley South to Valley North to Vista and Centralized BESS in Valley South	8. 58	11.81	3.85
SDG&E and Centralized BESS in Valley South	7.61	11.43	5.26
Valley South to Valley North	10.41	12.65	4.61

6.5 Summary of Findings

The evaluation of findings from the variety of benefit-cost analyses are presented below:

1. Without a project in service to address the needs in the Valley South System, the aggregate cost impacts accrued by the customer range from 2.7$B to 7.8$B over the horizon of forecast uncertainties captured by this analysis.
2. The benefit-cost analysis demonstrates Menifee as the project with the highest B-C ratio in Effective PV, Spatial Base, and PVWatts forecast. This is followed by the Alberhill System project and San Diego Gas & Electric. In the case of Valley South to Valley North alternatives, the project's low cost overrides the performance benefits and drive the ratios higher. The Menifee alternative has an advantage of lower cost while providing superior performance to Valley South to Valley North alternatives in select (Flex-2) categories. However, the benefits are realized only in the short

term horizon, with limited long-term benefits. A quick review of the overall benefits in Section 6.3.3 and raw reliability performance in Section 5.3.3, 5.3.5 and 5.3.6 further justifies this claim. The benefits accrued by ASP were found to be substantial over the horizon maintaining its rank across all three forecasts.

3. An evaluation of the $/Unit Benefit demonstrates that non-wire alternatives are favorable only under lower levels of forecasted growth. This is observable from the ranking of projects presented in Section 6.3.5.
4. Wire-based solutions demonstrate higher $/Unit benefit performance under the Effective PV and Spatial Base forecasts of load growth.
5. The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected. Using the Effective PV forecast as an example, if a decision is made to stop at Menifee due to superior performance in comparison to Valley South to Valley North to Vista and Baseline system, several projects are found to provide additional benefits to the system. This trend continues till a decision is made to stop at Alberhill System Project.
6. An overall assessment of the top-ranking alternatives with consideration of risks, demonstrate the superiority of ASP to meet all the short term and long-term project objectives in the Valley South System.

7 CONCLUSIONS

SCE retained Quanta Technology to supplement the existing record in the CPUC proceedings for SCE's ASP with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this analysis is to amend the ASP business case (including BCA) and alternative study using rigorous and data-driven methods.

A comprehensive framework was developed in coordination with SCE to evaluate and rank the performance of alternatives. This evaluation is complemented by the development of load forecasts for the Valley South System planning area. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for alternatives used power flow studies in coordination with quantitative analysis to forecast the impacts of alternatives under evaluation, including the ASP. The forecasted impacts are translated into key reliability metrics, representative of project performance over a 30-year horizon. Detailed analysis of alternatives used the benefit-cost and risk analysis framework to quantify the value of monetary benefits observed over the project horizon.

A total of 13 alternatives, including the ASP, were evaluated within this framework to validate performance and contribution towards satisfying project objectives. These alternatives were categorized into Minimal Investment, Conventional, Non-Wire, and Hybrid (Conventional plus Non-Wire) solutions.

The key findings of this study are summarized as follows:

- Consistent with the industry-accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely conventional and spatial forecasts. (The load forecasting methodologies and findings are documented in detail within Section 2 of this report.)
    - The two forecasts have been developed consistent with the load-growth trend currently observed within the region, and CEC's IEPR projections for load-reducing technologies.
    - Sensitivity analysis was performed to address the uncertainties of load-reducing technologies and California's electrification goals.
    - Across the three forecasts, the reliability need year was identified as 2022, except for one sensitivity that identified 2021 as the need year.
    - The Effective PV spatial load forecast is found to be the most consistent with trends in the Valley South needs area. This forecast demonstrates a range of load from 1,083 MVA to 1,377 MVA over 2019–2048.
- Several reliability metrics were used to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that the ASP provides the highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resilience, and operational flexibility needs in the Valley South System.

Considering the aggregated benefits under normal and emergency[12] conditions, the ASP results in 76 gigawatt-hours (GWh) of cumulative reduced unserved energy, and $4.3 billion in cost savings to the customers. The alternatives demonstrating the highest benefits following the ASP are SDG&E, SCE Orange County, and SDG&E with Centralized BESS in Valley South.

- The BCA framework was implemented to evaluate and compare individual alternatives' performance.
  - NWAs remained cost-effective only under reduced load forecast levels (e.g., reduced trend and low sensitivities of the conventional forecasts). In the other forecasts, NWAs accrue significant additional costs over time due to the incremental storage sizing necessary to address the load growth in the Valley South System.
  - Conventional and Hybrid alternatives can better satisfy project objectives and long-term reliability challenges in the system.
  - Menifee, ASP, SDG&E, and Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Menifee and Valley South to Valley North have lower costs relative to the ASP while providing sizably lower benefits than the ASP.
- The benefit-to-cost ratio is one measure to consider in determining if any project should be implemented. However, when it comes to the selection among alternatives, an incremental BCA should be conducted. Incremental BCA methodology determines whether additional incremental cost is economically justifiable on the basis that the additional benefits realized exceeds the incremental cost.
- The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected.
- Risk analysis associated with forecast uncertainties demonstrate that:
  - The costs associated with the incremental size of the NWAs (to keep pace with peak load values) are substantial and result in reduced benefit-cost ratios.
  - The benefits attributed to operational flexibility from NWAs are negligible.
- The results of the reliability, benefit-cost, and risk analyses indicated that the ASP meets the project objectives over the 10-year horizon and ranks the most favorable among the considered alternatives over the 30-year horizon.

Findings and results reported in this document are based on publicly available information along with the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

[12] N-0, N-1 and operational flexibility.

8 REFERENCES

[1] Quanta Technology, *Alberhill System Project Load Forecast,* 2019.

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[12] CPUC, *3. Decision Granting Petition to Modify Permit to Construct the Valley-Ivyglen 115 kV Sub-transmission Line Project and Holding Proceeding Open for Certificate of Public Convenience and Necessity for The Alberhill System Project,* 2018.

[13] Quanta Technology, *Alberhill System Project Load Forecast,* 2019.

9 APPENDIX: N-2 PROBABILITIES

The N-2 probabilities associated with circuits that share a common tower structures are presented in this table.

	Auld-Moraga #2	Auld-Sun City	Fogarty-Ivyglen	Moraga-Pechanga	Pauba-Triton	Valley-Auld #1	Valley-Auld #2	Valley-Elsinore-Fogarty	Valley-Newcomb	Valley-Newcomb-Skylark	Valley-Sun City	Valley-Auld-Triton	Valley-Ivyglen
Auld-Moraga #2				0.0088	0.0194							0.02696	
Auld-Sun City										0.0304			
Fogarty-Ivyglen													0.0032
Moraga-Pechanga	0.0088												
Pauba-Pechanga													
Pauba-Triton	0.01944											0.002	
Valley-Auld #1							0.0698						
Valley-Auld #2						0.0698						0.016	
Valley-Elsinore-Fogarty									0.024				
Valley-Newcomb								0.024					
Valley-Newcomb-Skylark		0.0304									0.0309		
Valley-Sun City										0.03096			
Valley-Auld-Triton	0.02696				0.002		0.016						
Valley-Ivyglen			0.0032										

EXHIBIT G-2 (SECOND AMENDED) REDLINE

Item G:

Cost/benefit analysis of several alternatives for:

- Enhancing reliability;
- Providing additional capacity including evaluation of energy storage, distributed energy resources, demand response or smart grid solutions.

Response to Item G

Revision 1.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This Second Amended Motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 1

Revision Date: January 29, 2021

Summary of Revisions:

This revision modifies the cost benefit analysis to correct various errors and to clarify specific elements of the analysis. These changes are summarized in Supplemental Data Response to Item C[1] and in the attached revised report by Quanta Technologies.

[1] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

The attached report, prepared by Quanta Technology as a contractor to Southern California Edison (SCE), provides a cost-benefit analysis comparing several alternatives, including the Alberhill System Project (ASP). The identification of alternatives and methodology for this cost-benefit analysis are described in the Quanta Technology report and summarized with additional context in the response to DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C (Planning Study).

This cost-benefit analysis is one factor among many which informs and supports SCE's recommended solution[2]. Other factors integrated into SCE's analysis and informing SCE's recommended solution include, but are not limited to, benefits achieved in both the near and long term, potential environmental impacts, input from the general public and other stakeholders, and other risk considerations.

[2] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item I.

A Appendix: Quanta Cost Benefit Analysis

The Quanta Technology report, *Cost Benefit Analysis of Alternatives Version 2.1 (Second Amended Motion)*, which includes supporting cost benefit spreadsheets, is attached as Appendix A to this data submittal.

Deliverable 3: Benefit Cost Analysis of Alternatives

REPORT

PREPARED FOR

Southern California Edison (SCE)

DATE

~~January 27~~June 15, 2021
~~(~~Version 2.~~0~~1(Errata)

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The following individuals participated and contributed to this study:

- Rahul Anilkumar
- Gerardo Sanchez
- Ali Daneshpooy
- Hisham Othman
- Ehsan Raoufat
- Lee Willis

VERSION HISTORY:

Version	Date	Description
0.1	11/14/2019	First Draft
0.2	12/5/2019	Second Draft
1.0	1/3/2020	Final Report
2.0	1/27/2021	This revision corrects errors identified in the cost-benefit analysis results. Specifically: • Modifying the treatment of reliability benefits into Load at Risk (LAR) without probability weighting. This includes N-1, Flex -1 and Flex – 2 benefit categories. • For monetization purposes, reliability benefits are translated into Expected Energy Not Served (EENS) by consideration of average load at risk over duration of event. • Treatment of N-1 and N-2 probabilities associated with events in the Valley South System. • Treatment of probabilities associated with Flex-2-2 event. • Separating costs from two customer classes (commercial and residential) to three customer classes (Residential, Small & Medium Industries and Commercial)

		• Modifying the definition of Flex-2-1 and Flex-2-2 events to no longer constrain the events that drives the impact to occur at peak summer load conditions. The events now account for varying conditions throughout the years. • Updated Present Value of Revenue Requirements (PVRR) and Total costs associated with alternatives. • Removing consideration for SAIDI, SAIFI and CAIDI from the reliability metrics, which were previously provided for information purposes only. • Project scope and associated costs have been added to several alternatives to address N-1 line capacity violations that occur within the first ten years of the project planning horizon. • The market participation revenues for alternatives that include Battery Energy Storage Systems (BESS) were modified to include Resource Adequacy payments for the eight months of the year where the BESS would not be dedicated to the system reliability need. • Other minor editorial corrections and clarifications.
2.1(Errata)	6/15/2021	This revision corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the reports are unaffected.

EXECUTIVE SUMMARY

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for SCE's Alberhill System Project (ASP) with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this study is to amend the ASP business case (including the benefit-cost analysis [BCA]) and alternative study using rigorous and data-driven methods.

A comprehensive framework was developed in coordination with the SCE study team to evaluate and rank the performance of alternatives. This evaluation is complemented by the development of load forecasts for the Valley South System planning area. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for the alternative projects is based on power flow studies in coordination with quantitative analysis to forecast the impacts of each alternative under evaluation, including the ASP. The projects' performance impacts are translated into key reliability metrics, representative of project performance over a 30-year horizon. Detailed analysis of the alternatives using benefit-cost and risk analysis frameworks to quantify the value of monetary benefits over the project horizon was conducted.

A total of 13 alternatives, including the ASP, were studied within this framework to evaluate their performance and contribution towards the project objectives. These alternatives were categorized as follows:

- Minimal investment
- Conventional
- Non-wires alternative (NWA)
- Hybrid (conventional plus NWA)

Highlights of the study are as follows:

- Consistent with industry-accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely conventional and spatial forecasts. (The load forecasting methodologies and findings are documented in detail within Section 2 of this report.)
    - The two forecasts have been developed consistent with the load-growth trend currently observed within the region and the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) projections for load-reducing technologies.
    - Sensitivity analysis was performed to address the uncertainties such as load-reducing technologies and the state of California's electrification goals.
    - Across the considered forecasts, the reliability need year was identified as 2022 (except for one sensitivity that identified 2021 as the need year).

    - The Effective PV Spatial load forecast is found to be the most consistent with the load-growth trend in the Valley South area. This forecast demonstrates a range of loading from 1,083 to 1,377 MVA from the year 2019 to 2048.
- Several reliability metrics were used to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that the ASP provides the highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resilience, and operational flexibility needs in the Valley South System. Considering the aggregated benefits under normal and emergency[1] conditions, the ASP results in 76 gigawatt-hours (GWh) of cumulative reduced unserved energy and $4.3 billion in cost savings to the end customers. The alternatives demonstrating the next-highest benefits (following the ASP) are SDG&E, SCE Orange County, and SDG&E with Centralized BESS (battery energy storage system) in Valley South.
- The BCA framework was implemented to evaluate and compare alternatives performance:
    - NWA solutions remained cost-effective only under reduced load forecast levels (e.g., reduced trend and low sensitivities of the conventional forecasts). Under the other forecasts, NWAs accrue significant costs over time due to the incremental storage sizing necessary to address the load growth in the Valley South system.
    - Conventional and hybrid alternatives can better satisfy project objectives and long-term reliability challenges in the system.
    - Menifee, ASP, SDG&E, and the Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Menifee and Valley South to Valley North have lower costs relative to the ASP while providing sizably lower benefits than ASP.
- The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. However, when it comes to the selection among alternatives, an incremental BCA should be conducted. Incremental BCA methodology warrants that the additional incremental cost is economically justifiable only if the benefit realized exceeds the incremental cost. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as type of project (reliability versus economic),environmental impact and risks.
- The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected.
- Risk analysis associated with forecast uncertainties demonstrates that:
    - The costs associated with the incremental size of the NWAs (to keep pace with peak load values) are substantial and result in reduced benefit-to-cost ratios.
    - The benefits attributed to operational flexibility from NWAs are negligible.
- The results of the reliability, benefit-cost, and risk analyses indicated that the ASP meets the project objectives over the 10-year horizon and ranks as the most favorable among the considered alternatives over a 30-year period.

[1] N-0, N-1, and operational flexibility.

Findings and results reported in this document are based on publicly available information along with the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

TABLE OF CONTENTS

List of Figures

List of Tables

List of Acronyms and Abbreviations

Term	Definition
AAEE	additional achievable energy efficiency
AAPV	additional achievable photovoltaic
AC	alternating current
ACSR	aluminum conductor steel-reinforced (cable)
AMI	advanced metering infrastructure
AS	ancillary service
ASP	Alberhill System Project
BCA	benefit-cost analysis
BES	bulk electric system
BESS	battery energy storage system
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CEC	California Energy Commission
CIGRE	International Council on Large Electric Systems
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
DA	day-ahead
DER	distributed energy resource
EENS	expected energy not served
ENA	Electrical Needs Area
EV	electric vehicle
GWh	gigawatt-hours
HILP	high-impact low-probability (event)
IERP	Integrated Energy Policy Report (of the California Energy Commission)
IP	interrupted power
ISO	independent system operator
LAR	load at risk

Term	Definition
LMDR	load modifying demand response
LMP	locational marginal price
LTELL	long-term emergency loading limits
MBCA	marginal benefit-to-cost analysis
MEA	mutually exclusive alternatives
NERC	North American Electric Reliability Corporation
NWA	non-wires alternative
O&M	operations and maintenance
PATHWAYS	a long-horizon energy model developed by Energy and Environmental Economics, Inc.
PFD	period of flexibility deficit
PV	photovoltaic
PVRR	present value of revenue requirements
RA	Resource Adequacy
RegDown	Regulation down
RegUp	Regulation up
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SOC	state of charge
STELL	short-term emergency loading limits
VO&M	variable operations and maintenance
VSSP	Valley South 115 kV Subtransmission Project
WACC	weighted aggregate cost of capital
WECC	Western Electricity Coordinating Council

1 INTRODUCTION

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV System. The overall objective of this analysis is to present a business case (including benefit-cost analysis [BCA]) justifying the appropriate project solution through data-driven quantitative methods and analysis.

In this section of the report, the project background, scope of work, study objective (including task breakdown), and study process have been outlined.

1.1 Project Background

Valley Substation is a 500/115 kV substation that serves electric demand in southwestern Riverside County. Valley Substation is split into two distinct 500/115 kV electrical systems: Valley North and Valley South. Each is served by two 500/115 kV, 560 MVA, three-phase transformers. The Valley South 115 kV System is not supplied power by any alternative means other than Valley Substation, nor does it have system tie-lines to adjacent 115 kV systems. In other words, this portion of the system is radially served by a single point of interconnection with the bulk electric system (BES) under the jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility,[2] and resilience needs of the Valley South System.

The Valley South 115 kV system Electrical Needs Area (ENA) consists of 14 distribution-level substations (115/12 kV substations). During the 2019–2028 forecast developed for peak demand, SCE identified an overload of the Valley South 500/115 kV transformer capacity by the year 2022 under normal operating conditions (N-0) and 1-in-5-year heat storm weather conditions. SCE has additionally identified the need to provide system tie-lines to improve reliability, resilience, and operational flexibility. To address these needs, the ASP was proposed. Figure 1-1 provides an overview of the project area.

Key features of this project are as follows:

- Construction of a 1,120 MVA 500/115 kV substation (Alberhill Substation).
- Construction of two 500 kV transmission line segments to connect the proposed Alberhill Substation by looping into the existing Serrano–Valley 500 kV transmission line.
- Construction of approximately 20 miles of 115 kV subtransmission line to modify the configuration of the existing Valley South System to allow for the transfer of five 115/12 kV distribution substations

[2] Flexibility or Operational Flexibility are used interchangeably in the context of this study. It is considered as the capability of the power system to absorb disturbances to maintain a secure operating state. It is used to bridge the gap between reliability and resilience needs in the system and overall planning objectives. Typically, system tie-lines allow for the operational flexibility to maintain service during unplanned equipment outages, during planned maintenance and construction activities, and to pre-emptively transfer load to avoid loss of service to affected customers. System tie-lines may effectively supplement transformation capacity by allowing the transfer of load to adjacent systems.

from the Valley South System to the new Alberhill System and to create 115 kV system tie-lines between the two systems.

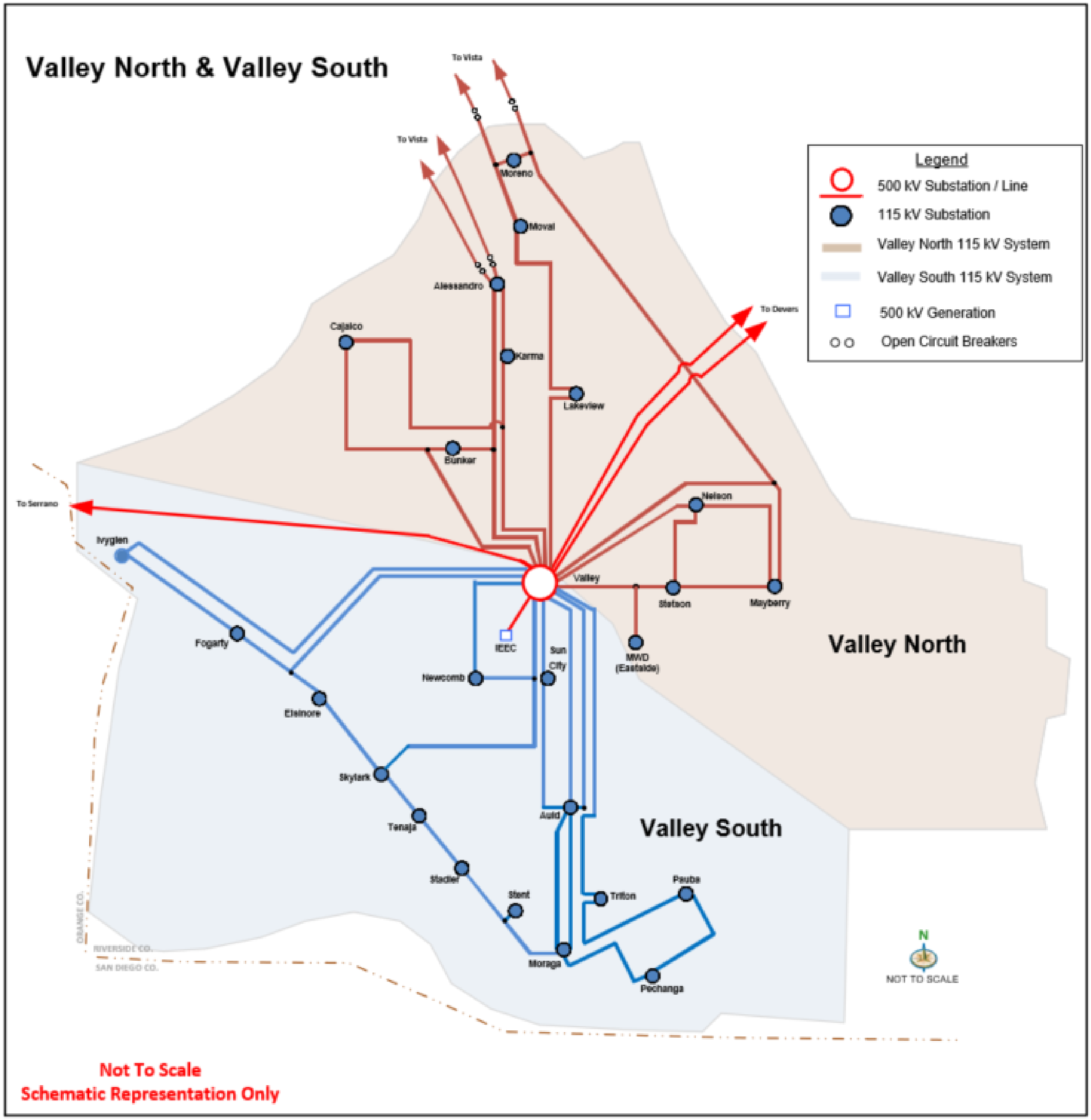


Figure 1-1. Valley Substation Service Areas[3]

SCE subsequently submitted an application to the CPUC seeking a Certificate of Public Convenience and Necessity (CPCN). During the final stage of the ASP proceeding, the CPUC directed SCE to provide

[3] Valley-Ivyglen and VSSP projects included [12]

additional analyses to justify the peak demand forecasts and reliability cases in support of justifying the project. The CPUC also directed SCE to provide a comparison of the proposed ASP to other potential system alternatives that may satisfy the stated project needs; these included, but were not limited to, energy storage, demand response, and distributed energy resources (DERs).

1.2 Scope of Work

Quanta Technology supported SCE in supplementing the existing record in the CPUC proceeding for the ASP with additional analyses including a forecast using industry-accepted methods of load forecast and additional alternatives including DERs to address any system needs established by the load forecasts to provide the necessary facilities to meet the capacity and reliability needs of the Valley South 500/115 kV system. The key scope items of the Quanta Technology analysis are detailed below:

1. Apply a rigorous, quantitative, data-driven approach to comprehensively present the business case justifying the appropriate project solution. The business case justification included a BCA of the alternatives considered based on the forecasted improvements in service reliability performance of the Valley South System. To this effect, Quanta Technology developed a load forecast for the Valley South System planning area using industry-accepted methods for estimating load growth and incorporating load-reduction programs due to energy efficiency, demand response, and behind-the-meter generation. Quanta Technology's forecasting exercise was developed independently of SCE's current forecasting methodology and practices; however, both SCE's and Quanta Technology's analysis incorporated the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) forecasts for the first 10 years through 2028.
2. Using power flow simulations and a quantitative review of project data, the forecasted impact of the proposed ASP on service reliability performance was estimated.
3. Identification of capital investments or operational changes to address reliability issues in the absence of construction of the proposed ASP or any other major projects requiring CPUC approval, along with the associated costs for such actions.
4. BCA of several system alternatives (including the proposed ASP, alternative substations and line configurations, energy storage, DER, demand response, and other smart-grid solutions or combinations thereof) for enhancing reliability and providing the required additional capacity.

The primary component of this work statement was to identify a number of system alternatives (e.g., alternative substation and line configurations, energy storage, DER, demand response, other smart-grid solutions, or combinations thereof [hybrid projects]) to satisfy the peak-demand load projections and reliability needs over a 30-year planning horizon. This was followed by a system analysis using a data-driven quantitative assessment of project performance, coupled with BCA of the proposed project and several of these alternatives, to allow objective comparison of their costs and benefits. Additionally, all system alternative designs were developed to satisfy the following project objectives[4] as stipulated by the project proceedings:

[4] For purposes of alternatives analysis SCE directed Quanta to refer to the original project objectives identified by SCE in its Proponents Environmental Assessment (PEA) that was filed with SCE's application because the project objectives as listed in the Final Environmental Impact Report (FEIR) identified that a solution must include a new 500/115 kV substation. During the ASP proceeding, the CPUC directing SCE to evaluate additional alternatives that…

1. Serve current and long-term projected electrical demand requirements in the SCE ENA.
2. Increase system operational flexibility and maintain system reliability (e.g., by creating system tie-lines that establish the ability to transfer substations located in the Valley South System).
3. Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity through the 10-year planning horizon.
4. Provide safe and reliable electrical service consistent with the SCE's Subtransmission Planning Criteria and Guidelines.
5. Increase electrical system reliability by constructing a project in a location suitable to serve the SCE ENA (i.e., the area served by the existing Valley South System).
6. Meet project needs while minimizing environmental impacts.
7. Meet project needs in a cost-effective manner.

1.3 Methodology

In order to accomplish the scope of this project, the following tasks were employed to meet the overall objectives of this effort:

- Task 1: Detailed Project Planning
- Task 2: Development of Load Forecast for the Valley South System
- Task 3: Reliability Assessment of ASP
- Task 4: Screening and Reliability Assessment of Alternatives
- Task 5: Benefit-Cost Analysis

The objective of each of the project tasks is detailed in the following subsections.

1.3.1 Task 1: Detailed Project Planning

The objective of this task was to develop a detailed and structured work plan that includes a description of the proposed load-forecasting methodology, overall study process, data needs, interim deliverables, and timeline of activities to meet the project deliverables. The key outcomes of this task were to review and finalize assumptions, methodology, metrics, and overall approach for the following key aspects of the project:

- Load forecasting methodology
- Data-driven, quantitative reliability metrics
- Reliability assessment and benefit-cost framework
- A detailed project plan including interim deliverables and schedule

…included DERs. To comprehensively perform this analysis would have been necessarily constrained by the project objectives as stated in the FEIR, thus reverting back to SCE's project objectives in its PEA (which did not specify a solution as requiring a new 500/115 kV substation) was most suitable to perform the required alternatives analysis.

1.3.2 Task 2: Development of Load Forecast for the Valley South System

The objective of this task was to develop a baseline load forecast representative of the 10-year horizon and a long-term forecast to account for the 30-year horizon. Forecasts have been developed for Valley North and Valley South Systems. The long-term forecasts are developed accounting for varying projections around energy efficiency, demand response, and behind-the-meter aggregations.

1.3.3 Task 3: Reliability Assessment of ASP

The objective of this task was to introduce the reliability assessment framework while describing the tools, formulation, and overall methodology. The proposed performance metrics are introduced, and their applicability has been described. Subsequently, the reliability framework was applied to the ASP and the overall project performance was evaluated.

1.3.4 Task 4: Screening and Reliability Assessment of Alternatives

The objective of this task was to analyze alternative projects (and their operational considerations) being considered to address the reliability needs in the absence of the ASP. Through a screening process, the selected set of alternative projects are evaluated using the reliability framework to quantify their performance.

1.3.5 Task 5: Benefit-Cost Analysis

The objective of this task was to perform a BCA of the ASP along with the list of system alternatives from Task 4. This analysis intended to compare the project alternatives using the quantitative reliability metrics developed in Task 1 along with rigorous cost and risk analysis that will be required to justify the business case of each alternative for meeting the load growth and reliability needs of the Valley South System.

1.4 Report Organization

This report has been organized consistent with the tasks outlined in Section 1.3. The report has been separated into several sections that individually address each task item. The intent of this breakdown is to capture, in detail, the essential elements of the reliability and benefit-cost framework.

In Section 2 of this report, the long-term spatial load forecast is discussed. This section is complementary to Quanta Technology's load forecast report [1], which focused on the near-term load forecast and describes the technical details behind the spatial load forecasting methodology.

Section 3 of this report presents the overall framework for reliability and benefit-cost evaluation. This highlights the study methodology, assumptions, and describes key processes involved in the analysis.

In Sections 4 and 5, the reliability evaluation framework is applied to the ASP and selected alternatives. Each of the forecasts developed in Task 2 is applied to evaluate the alternative's performance.

Section 6 presents the results from the BCA and deterministic risk assessment.

Section 7 presents the report conclusions and is followed by applicable references (Section 8) and an appendix (Section 9) that provides the N-2 probabilities associated with circuits that share a common tower structures.

2 LONG-TERM SPATIAL LOAD FORECAST

The spatial load forecast for the Valley North and Valley South Systems of the greater SCE system was developed for a long-term period of 30 years, covering from 2019 to 2048. The horizon year of 2048 assumed all general plan land use maps for Valley North and Valley South communities are designed for the 30-year horizon. Forecast results up to the year 2028 were presented in a separate report [1]. This forecast was constructed from a baseload forecast and incorporated DER development according to CEC's 2018 IEPR [2] and SCE's dependable photovoltaic (PV) disaggregation. The result was a disaggregated effective PV forecast that expanded the 10-year PV forecast for the Valley North and Valley South regions to the 30-year timeframe. This section describes the methodology used to develop the additional 20 years of the load forecast (2029–2048) and considers three DER development scenarios.

2.1 Base spatial load forecast

The spatial load forecasting method developed by Quanta Technology was presented in [1], where base forecast results were shown up to the year 2028. This spatial forecast methodology is based on a 30-year horizon year,[5] and results were obtained for the entire period.

These forecast results are representative of the natural load growth resulting from incremental use of electricity by existing customers and new customer additions as indicated by future land use plans. The sum of these two factors provides the base spatial forecast that does not include the effects of future DER developments. Embedded within these results are the current levels of DER adoption observed by the base forecast. The results are summarized in Table 2-1. Further details on the spatial load forecast methodology, can be found in [1].

Table 2-1. Base Spatial Load Forecast without Additional Impacts of Future DER

Year	Spatial Valley South (No added DER) [MVA]	Spatial Valley North (No added DER) [MVA]
2018	1068	769
2019	1092	787
2020	1116	804
2021	1142	825
2022	1162	845
2023	1181	857
2024	1193	866
2025	1205	874

[5] The 30-year horizon year was selected as a typical long-term planning range that allows accommodating such things as the time required for regulatory licensing and permitting activities as well as lead times and financial budgeting for utility equipment and construction as required.

Year	Spatial Valley South (No added DER) [MVA]	Spatial Valley North (No added DER) [MVA]
2026	1217	882
2027	1229	893
2028	1242	904
2029	1254	915
2030	1267	925
2031	1280	938
2032	1293	950
2033	1306	963
2034	1319	975
2035	1331	989
2036	1344	1002
2037	1356	1015
2038	1369	1029
2039	1380	1042
2040	1392	1055
2041	1404	1068
2042	1415	1081
2043	1425	1093
2044	1436	1105
2045	1446	1117
2046	1456	1129
2047	1465	1140
2048	1474	1150

2.2 DER Development from 2019 to 2028

Based on IEPR 2018, SCE provided disaggregated DER forecasts to the level of the Valley South and Valley North systems. These DER forecasts covered from 2019 to 2028 and included additional achievable energy efficiency (AAEE), additional achievable photovoltaic (AAPV), electric vehicles (EVs), energy storage, and load modifying demand response (LMDR) categories.

2.2.1 AAPV Disaggregation

For AAPV, SCE provided two scenarios: 1) SCE Effective PV and 2) PVWatts. The final load forecast presented in [1] considers the SCE Effective PV scenario as the most likely scenario during the period from 2019 to 2028. AAPV values based on the SCE Effective PV forecast and AAPV values based on PVWatts impacts on peak load reduction are shown in Table 2-2.

Table 2-2. Disaggregated Forecasted Peak Modifying AAPV from 2019 to 2028

	DER Type (units in MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	AAPV SCE Effective PV	-4.9	-4.9	-4.9	-4.9	-4.9	-4.5	-4.0	-3.7	-3.7	-2.9
	AAPV PVWatts	-7.7	-7.6	-7.6	-7.5	-7.4	-6.8	-6.2	-5.8	-5.6	-4.3
Valley South	AAPV SCE Effective PV	-5.7	-5.0	-4.2	-3.4	-3.0	-2.8	-2.7	-2.4	-2.1	-1.9
	AAPV PVWatts	-8.9	-8.7	-8.6	-8.4	-7.8	-7.0	-7.0	-6.3	-5.6	-4.8

2.2.2 Disaggregation of Other DER Categories

Based on the 2018 IEPR, SCE also provided disaggregated DER forecasts for AAEE, EVs, energy storage, and LMDR categories. The forecasted peak-modifying amounts of DER are shown in Table 2-3.

Table 2-3. Disaggregated Forecasted Peak-Modifying DER from 2019 to 2028

	DER Type (units in MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	Electric Vehicle	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.2	0.2	0.3
	AAEE	-2.3	-2.1	-2.6	-2.8	-3.2	-2.9	-2.8	-2.7	-2.8	-2.9
	Energy Storage	-0.5	-0.1	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1
	LMDR	0.0	-0.5	0.0	-0.1	-0.2	-0.1	-0.1	0.0	0.0	0.0
Valley South	Electric Vehicle	0.8	0.9	0.8	0.6	0.7	0.6	0.6	0.4	0.4	0.4
	AAEE	-3.4	-2.9	-3.6	-2.6	-3.0	-2.8	-2.7	-2.5	-2.6	-2.8
	Energy Storage	-1.0	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1
	LMDR	0.6	-1.4	0.0	-0.2	-0.2	-0.1	-0.1	0.0	0.0	0.0

2.3 Forecasted DER Development 2029–2048

In order to obtain a long-term spatial forecast that considers the impacts of DERs, it is necessary to have DER forecasts that extend to the year 2048. The estimation of DER from the year 2029 until the year 2048 has been performed as described in the following subsections.

2.3.1 AAPV Growth from 2029 to 2048

Growth rates of generation forecasts for solar and rooftop PV have been taken from the California PATHWAYS model [3], on its CEC 2050 scenario. The same yearly growth rates for the state of California have been applied to the AAPV forecasts of Table 2-2, starting from the year 2029, to generate an estimation of the AAPV in the Valley South and Valley North Systems up to the year 2048. The estimated AAPV at the Valley South and Valley North system level for the AAPV Effective PV and the AAPV PVWatts scenarios are shown in Table 2-4 and Table 2-5.

Table 2-4. California (CA) PATHWAYS CEC 2050 Case for the Solar Generation [MVA], and Estimated AAPV SCE Effective PV (in MVA) at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA Solar	75.7	80.6	86	92.1	95.8	100	105	111	117	124	132	139	146	152	157	162	167	172	176	179	183
CA PV	29.9	33	36.4	37.5	38.6	39.7	40.8	41.9	42.9	44	45.1	46.2	47.3	48.3	49.4	50.5	51.6	52.7	53.8	54.8	55.9
CA Total	106	114	122	130	134	140	146	153	160	168	177	185	193	200	207	213	219	225	230	234	239
AAPV Valley North	-2.9	-2.7	-2.5	-2.3	-2.2	-2.1	-2.1	-2	-1.9	-1.8	-1.7	-1.6	-1.5	-1.5	-1.4	-1.4	-1.3	-1.3	-1.3	-1.3	-1.2
AAPV Valley South	-1.9	-1.8	-1.6	-1.5	-1.5	-1.4	-1.4	-1.3	-1.2	-1.2	-1.1	-1.1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8

Table 2-5. California (CA) PATHWAYS CEC 2050 Case for the Solar Generation [MVA], and Estimated AAPV PVWatts (in MVA) at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA Solar	75.7	80.6	86	92.1	95.8	100	105	111	118	124	132	139	146	152	157	162	167	172	176	180	183
CA PV	29.9	33	36.5	37.5	38.6	39.7	40.8	41.9	42.9	44	45.1	46.2	47.3	48.4	49.4	50.5	51.6	52.7	53.8	54.8	55.9
CA Total	106	114	123	130	134	140	146	153	160	168	177	185	193	200	207	213	219	225	230	234	239
AAPV Valley North	-4.3	-4	-3.6	-3.4	-3.3	-3.2	-3	-2.9	-2.7	-2.6	-2.5	-2.4	-2.3	-2.2	-2.1	-2	-2	-1.9	-1.9	-1.9	-1.8
AAPV Valley South	-4.8	-4.5	-4.1	-3.9	-3.7	-3.6	-3.4	-3.3	-3.1	-3	-2.8	-2.7	-2.6	-2.5	-2.4	-2.3	-2.2	-2.2	-2.1	-2.1	-2.1

As a third scenario for AAPV growth after 2028, a compound annual growth rate (CAGR) of 3% was used as a reasonable expectation for future AAPV after the year 2028. This is based on CEC IEPR PV forecast observations that around 2022 the natural adoption of PV starts to show plateau. The additional growth from zero net energy or new home installations is expected to be relatively flat for every year. That means it will not generate higher growth rates for PV forecast in the longer term. The reasonable growth rate for the disaggregated PV forecast going beyond 2028 is about -3%. The resulting estimations of peak reducing capabilities are shown in Table 2-6.

Table 2-6. Estimated AAPV PVWatts (in MVA) at Valley South and Valley North a -3% CAGR

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
AAPV Valley North	-2.9	-2.8	-2.7	-2.6	-2.6	-2.5	-2.4	-2.3	-2.3	-2.2	-2.1	-2.1	-2	-2	-1.9	-1.8	-1.8	-1.7	-1.7	-1.6	-1.6
AAPV Valley South	-1.9	-1.9	-1.8	-1.7	-1.7	-1.6	-1.6	-1.5	-1.5	-1.5	-1.4	-1.4	-1.3	-1.3	-1.2	-1.2	-1.2	-1.1	-1.1	-1.1	-1

Figure 2-1 and Figure 2-2 show the AAPV forecasted growth scenarios for Valley South and Valley North, respectively.

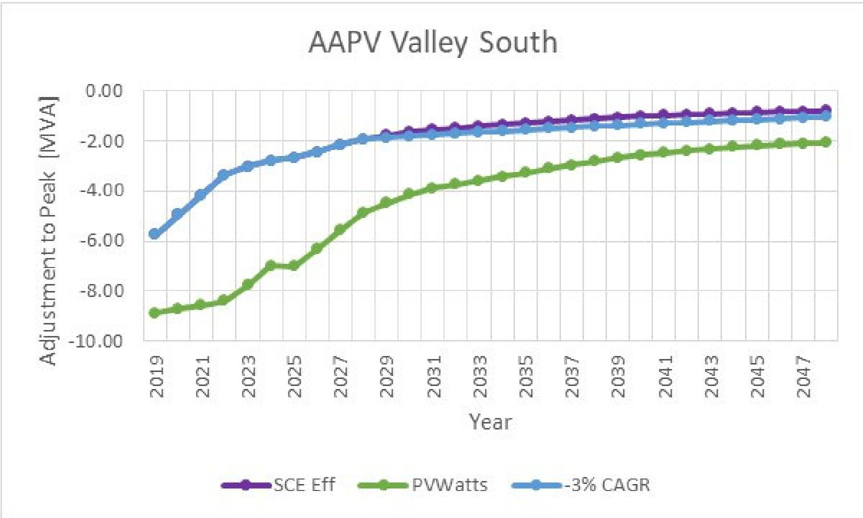


Figure 2-1. AAPV Forecasted Growth Scenarios for Valley South

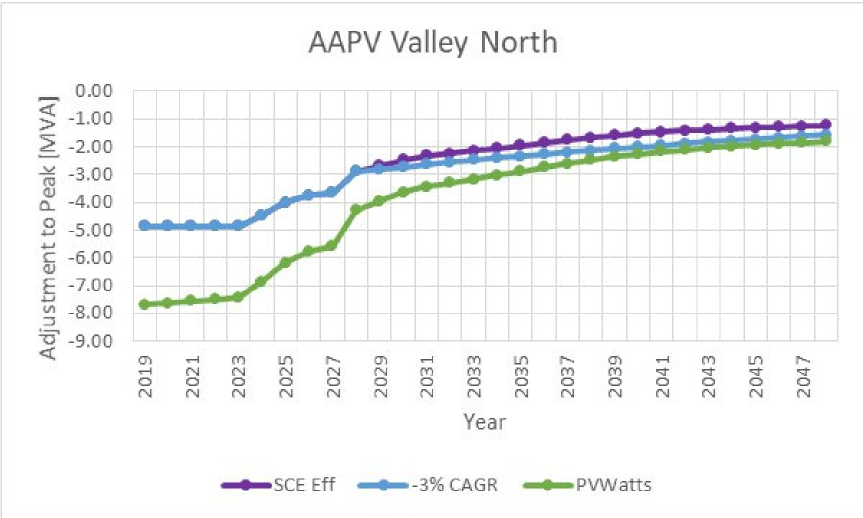


Figure 2-2. AAPV Forecasted Growth Scenarios for Valley North

2.3.2 EV Growth from 2029 to 2048

The EV disaggregated forecast of Table 2-3 was extended until the year 2048 by using growth rates of subsector electric demands for light-duty vehicles, taken from the California PATHWAYS model, on its CEC 2050 scenario. The same yearly growth rates for the state of California have been applied to the EV forecast of Table 2-3, starting from the year 2028. The estimated EV load at the Valley South and the Valley North System are shown in Table 2-7.

Table 2-7. California PATHWAYS CEC 2050 Case for the Light EV Load (in MVA), and Estimated EV [MVA] at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA EV	10.1	11.8	14	16.5	19.4	22.5	25.5	28.3	30.8	33.2	35.5	37.5	39.4	41.3	43	44.5	45.8	46.9	47.7	48.4	48.8
EV Valley North	0.28	0.32	0.38	0.45	0.53	0.62	0.7	0.78	0.85	0.91	0.97	1.03	1.08	1.13	1.18	1.22	1.26	1.29	1.31	1.33	1.34
EV Valley South	0.43	0.5	0.6	0.7	0.83	0.96	1.09	1.2	1.31	1.42	1.51	1.6	1.68	1.76	1.83	1.9	1.95	2	2.03	2.06	2.08

Figure 2-3 and Figure 2-4 show the forecasted amounts of peak-enhancing electric vehicle loads for Valley South and Valley North.

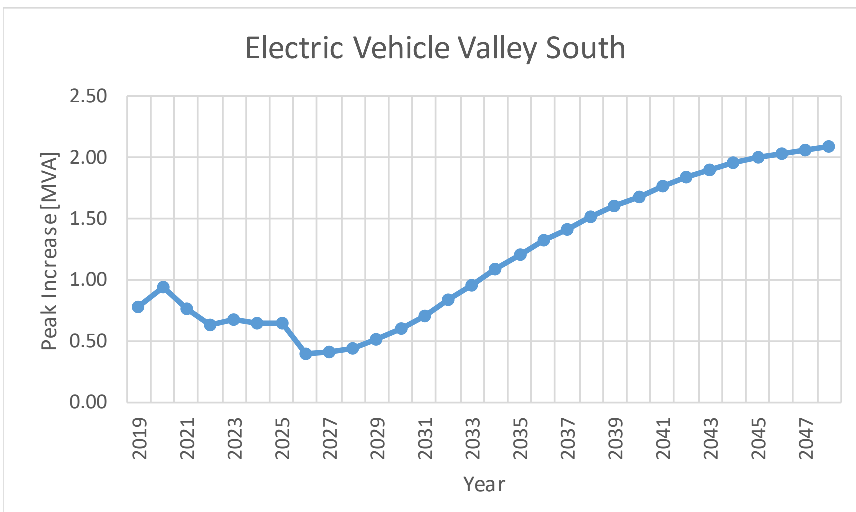


Figure 2-3. EV Forecasted Growth for Valley South

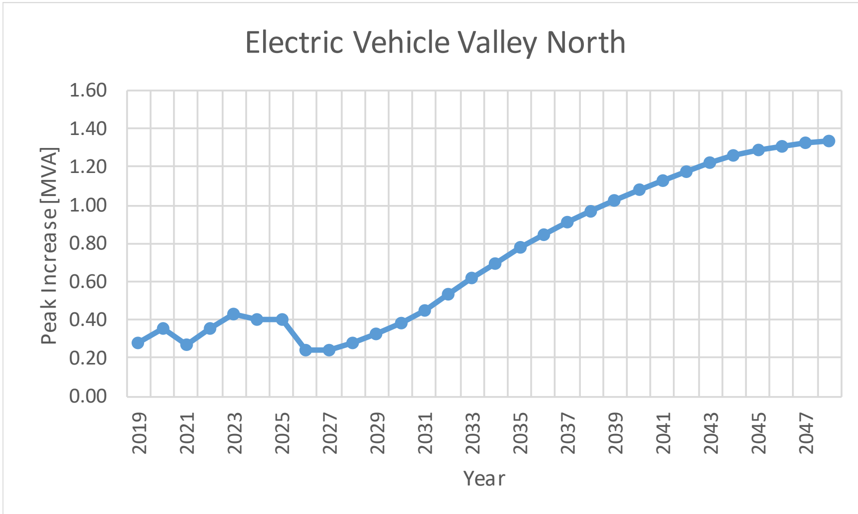


Figure 2-4. EV Forecasted Growth for Valley North

2.3.3 Energy Efficiency Growth from 2029 to 2048

The energy efficiency disaggregated forecast of Table 2-3 was extended until the year 2048 based on the criteria that after 2028 the load reductions in energy efficiency are expected to be close to 21% of the forecasted load growth of each year. Additionally, it is considered that energy efficiency load reductions will predominantly take place in residential loads, which are approximately 40% of the Valley South system load and approximately 36% of the Valley North System load. The resulting extended forecast for energy efficiency is shown in Table 2-8.

Table 2-8. Estimated Growth of Peak-Reducing Energy Efficiency at Valley South and Valley North (in MVA)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
EE Valley North	-0.8	-0.9	-0.9	-0.9	-0.9	-1	-1	-1	-1	-1	-1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8
EE Valley South	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1	-1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.7	-0.7	-0.7

Figure 2-5 and Figure 2-6 show the forecasted amounts of peak-reducing Energy Efficiency effect for Valley South and Valley North.

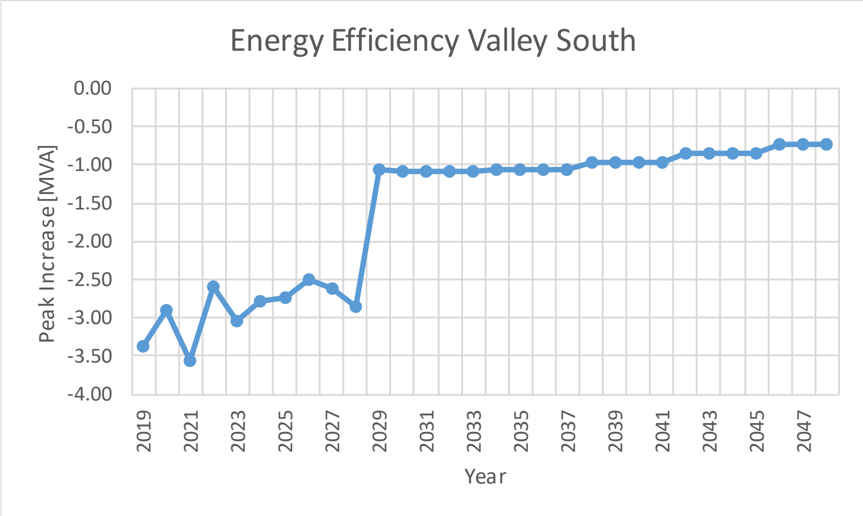


Figure 2-5. Energy Efficiency Forecasted Growth for Valley South

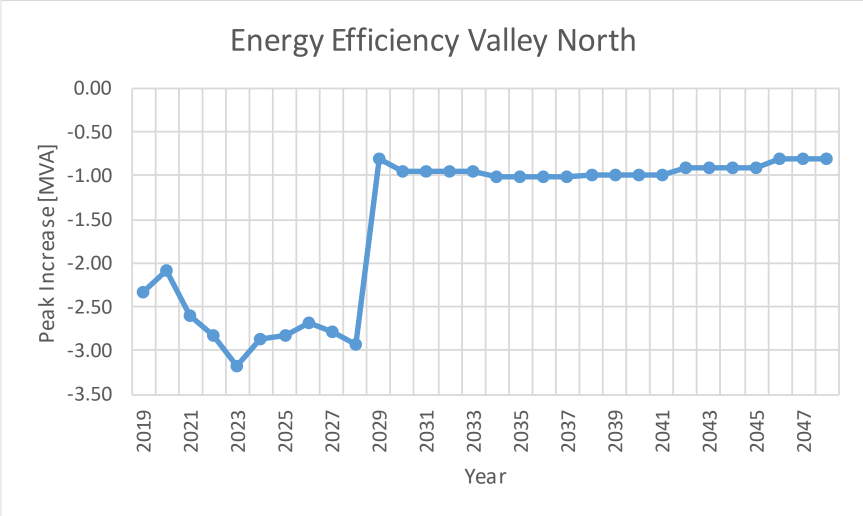


Figure 2-6. Energy Efficiency Forecasted Growth for Valley North

2.3.4 Energy Storage Growth from 2029 to 2048

SCE provided an energy storage outlook for the entire SCE service territory. This outlook estimated an approximated total of 4,300 MVA of energy storage by the year 2048. By SCE criteria, it was estimated that 60% of this storage would be associated with residential customers, of which approximately 5% would be located in the Valley South System and approximately 20% of it would have a peak reduction effect. These considerations lead to an estimated peak-reducing amount of cumulated energy storage of 26 MVA (or an additional 23.6 MVA after 2028) by 2048 for the Valley South System. Similar considerations lead to additional cumulated 15.5 MVA of peak reducing energy storage for the Valley North System.

A CAGR of energy storage was identified for each area (Valley North and Valley South) so that the year 2048 estimated values were achieved. The resulting CAGR for the Valley South system is 17.98%, and the same for Valley North is 14.39%. Table 2-9 summarizes the resulting estimated peak-reducing amounts of energy storage for the Valley South and Valley North Systems.

Table 2-9 Estimated Growth of Peak-Reducing Energy Storage at Valley South and Valley North (in MVA)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Storage Valley North	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.4	-0.4	-0.5	-0.5	-0.6	-0.7	-0.8	-0.9	-1.1	-1.2	-1.4	-1.6	-1.8	-2.1
Storage Valley South	-0.2	-0.2	-0.2	-0.3	-0.3	-0.4	-0.4	-0.5	-0.6	-0.7	-0.8	-1	-1.2	-1.4	-1.6	-1.9	-2.3	-2.7	-3.2	-3.7

Figure 2-7. and Figure 2-8 show the forecasted amounts of peak-reducing Energy Storage effect for the Valley South and Valley North Systems.

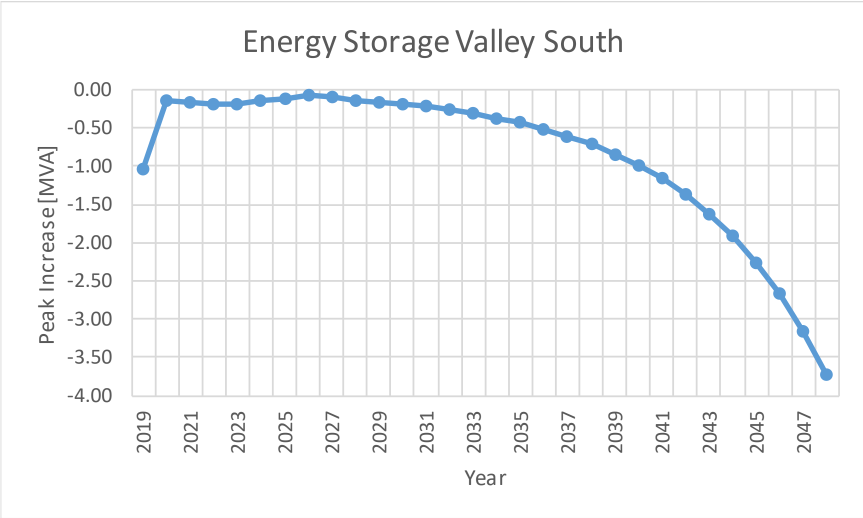


Figure 2-7. Energy Storage Forecasted Growth for Valley South

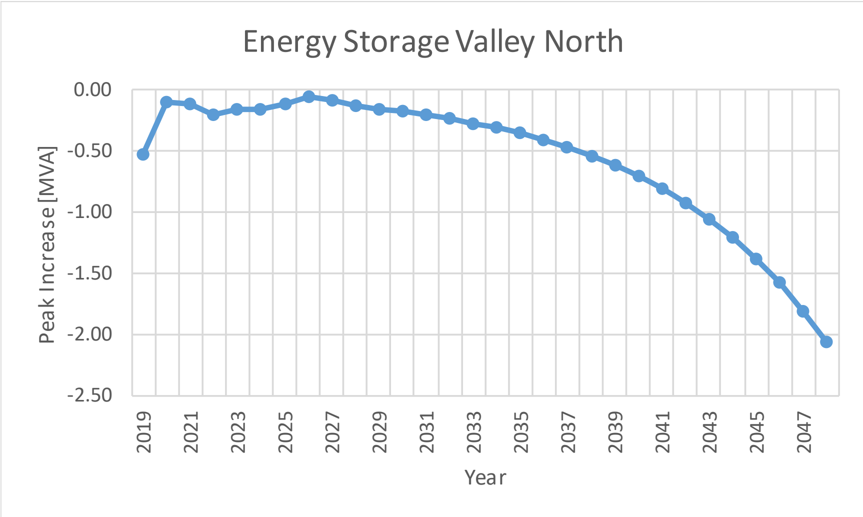


Figure 2-8. Energy Storage Forecasted Growth for Valley North

2.3.5 Demand Response Growth from 2029 to 2048

According to the demand response trends extracted from Table 2-3, the effects of demand response were considered negligible after the year 2028.

2.4 Valley South and Valley North Long-Term Forecast Results

The peak modifying effects for future DER discussed in the previous sections were aggregated and applied to the base spatial load forecast of Section 2.1 to develop long-term load forecast results for Valley South and Valley North. The resulting forecast scenarios are summarized in Table 2-10 and Figure 2-9 for the Valley South system and in Table 2-11 and Figure 2-10 for the Valley North System.

Table 2-10. Final Results of the Spatial Forecast for Valley South, Considering Three AAPV Growth Alternatives after the Year 2028

Year	Spatial Valley South (no added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2018	1068	1068	1068	1068
2019	1092	1083	1083	1083
2020	1116	1099	1099	1099
2021	1142	1118	1118	1118
2022	1162	1132	1132	1132
2023	1181	1146	1146	1146
2024	1193	1152	1152	1152
2025	1205	1159	1159	1159

Year	Spatial Valley South (no added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2026	1217	1166	1166	1166
2027	1229	1174	1174	1174
2028	1242	1183	1183	1183
2029	1254	1193	1177	1193
2030	1267	1203	1172	1203
2031	1280	1214	1166	1213
2032	1293	1225	1175	1224
2033	1306	1236	1184	1235
2034	1319	1247	1193	1246
2035	1331	1258	1202	1257
2036	1344	1269	1211	1267
2037	1356	1280	1221	1278
2038	1369	1291	1230	1289
2039	1380	1302	1239	1299
2040	1392	1312	1248	1309
2041	1404	1322	1256	1319
2042	1415	1333	1265	1329
2043	1425	1341	1272	1337
2044	1436	1350	1280	1346
2045	1446	1358	1287	1354
2046	1456	1366	1293	1361
2047	1465	1372	1298	1367
2048	1474	1378	1302	1373

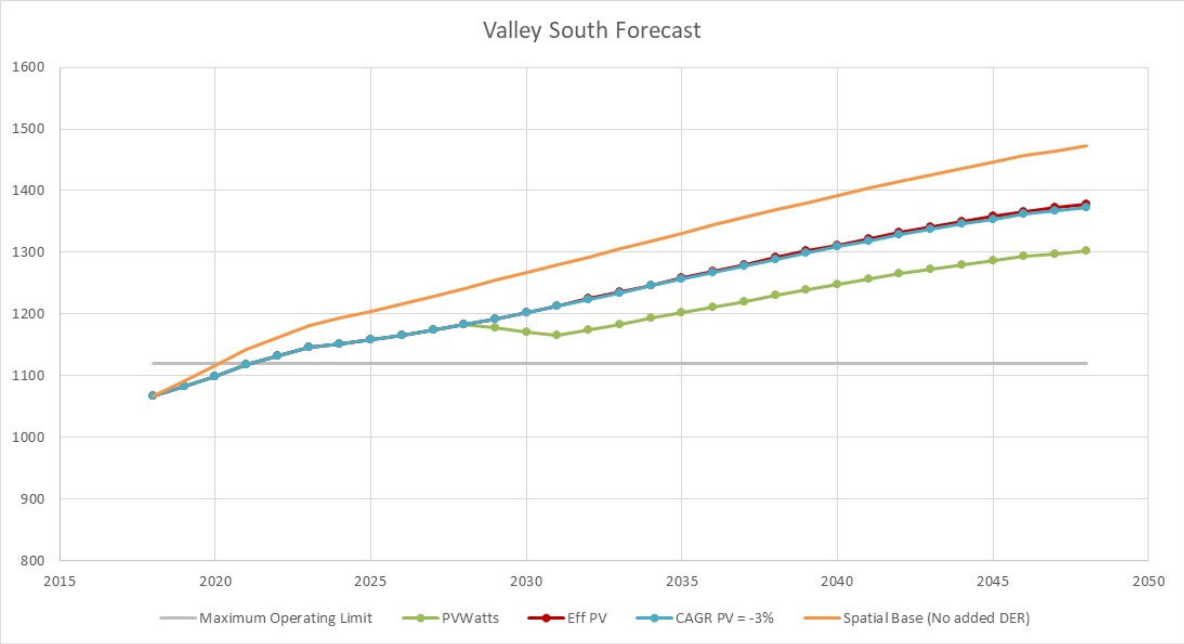


Figure 2-9. Final Results of the Spatial Forecast for Valley South, Considering Three AAPV Growth Alternatives after the Year 2028

Table 2-11. Final Results of the Spatial Forecast for Valley North, Considering Three AAPV Growth Alternatives after the Year 2028

Year	Spatial Valley North (No added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2018	769	769	769	769
2019	787	779	779	779
2020	804	789	789	789
2021	825	803	803	803
2022	845	816	816	816
2023	857	820	820	820
2024	866	821	821	821
2025	874	823	823	823
2026	882	825	825	825
2027	893	829	829	829
2028	904	834	834	834
2029	915	842	834	842

Year	Spatial Valley North (No added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2030	925	849	833	849
2031	938	859	832	858
2032	950	868	840	867
2033	963	878	849	877
2034	975	888	858	886
2035	989	899	868	897
2036	1002	910	878	907
2037	1015	921	888	918
2038	1029	932	898	928
2039	1042	943	908	939
2040	1055	954	919	949
2041	1068	964	929	960
2042	1081	975	939	970
2043	1093	985	948	980
2044	1105	995	958	989
2045	1117	1005	967	998
2046	1129	1015	976	1008
2047	1140	1023	983	1015
2048	1150	1031	991	1023

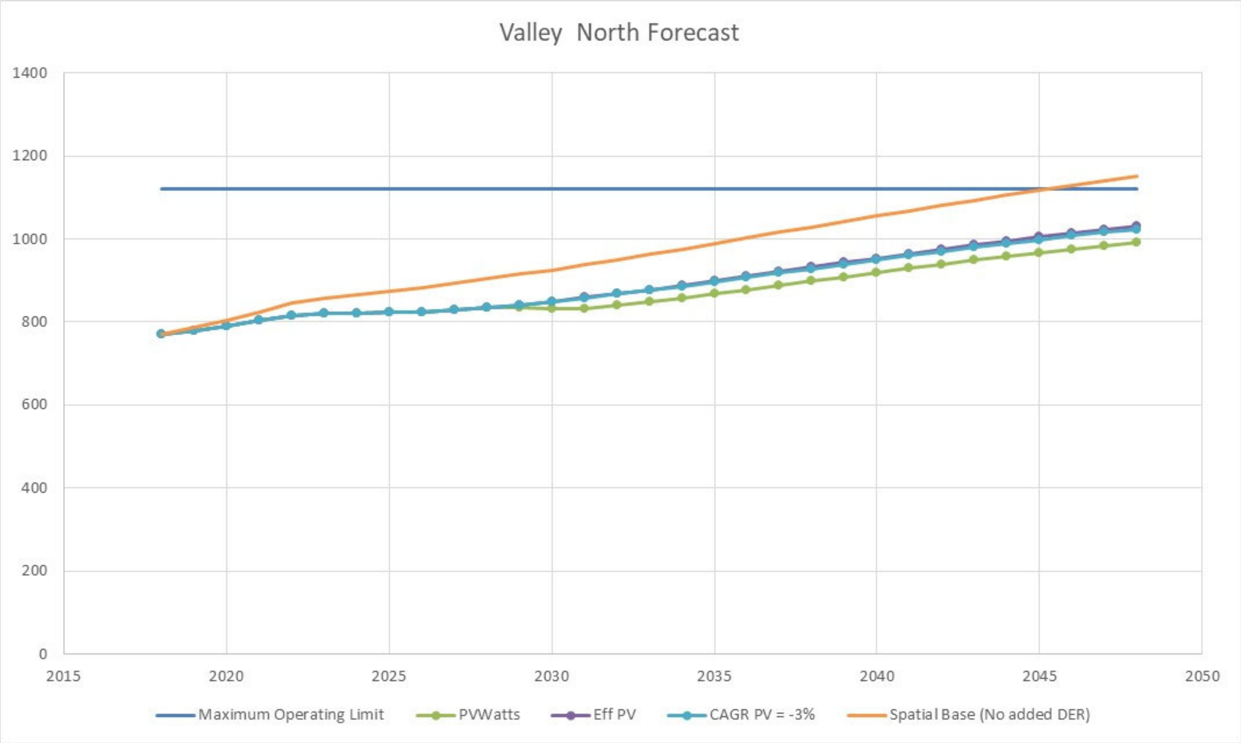


Figure 2-10. Final Results of the Spatial Forecast for Valley North, Considering Three AAPV Growth Alternatives after the Year 2028

3 RELIABILITY ASSESSMENT AND BENEFIT-COST FRAMEWORK

3.1 Introduction

The objective of this framework is to facilitate the evaluation of project performance and benefits relative to the baseline scenario (i.e., no project in service). The projects under consideration include the ASP and proposed alternatives discussed further in Sections 4 and5. Within the framework of this analysis, reliability, capacity, operational flexibility, and resilience benefits have been quantified.

In order to successfully evaluate the benefit of a potential project in the Valley South System, the project's performance must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance
2. To compare project performance to the baseline scenario (no project in service)
3. To establish a basis to value the performance of projects against overall objectives
4. To take into consideration the benefits or impacts of operational flexibility and resilience (high-impact low-probability events [HILP])
5. To compare and provide guidance for comparing the relative performance of each alternative as compared to others.

Within the scope of the developed metrics, the key project objectives presented earlier, are categorized and reviewed as follows:

- **Capacity**
  - Serve current and long-term projected electrical demand requirements in the SCE ENA.
  - Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through not only the 10-year planning horizon but also that of a longer-term horizon that identifies needs beyond 10 years, which would allow for an appropriate comparison of alternatives that have different useful lifespan horizons.

- **Reliability**
  - Provide safe and reliable electrical service consistent with the SCE Subtransmission Planning Criteria and Guidelines.
  - Increase electrical system reliability by constructing a project in a location suitable to serve the ENA (i.e., the area served by the existing Valley South System).

- **Operational Flexibility and Resilience**
  - Increase system operational flexibility and maintain system reliability (e.g., by creating system tie-lines that establish the ability to transfer substations from the current Valley South System and to address system operational capacity needs under normal and contingency (N-1) conditions.

3.2 Reliability Framework and Study Assumptions

In order to develop a framework to effectively evaluate the performance of a project, the overall study methodology was broken down into the following elements:

1. Develop metrics to establish project performance
2. Quantify the project performance using commercial power flow software
3. Establish a platform to evaluate monetized and non-monetized project benefits
4. Utilize tools such as benefit-to-cost ratio, incremental BCA, and $/unit benefit to substantiate alternative selection and conclusions.

Each of the above areas is further detailed throughout this section.

3.2.1 Study Inputs

SCE provided Quanta Technology with information pertinent to the Valley South, Valley North, and the proposed ASP systems. This information encompassed the following data:

1. GE PSLF power flow models for Valley South and Valley North Systems:
   a. 2018 system configuration (current system)
   b. 2021 system configuration (Valley–Ivyglen [4] and VSSP [5] projects modeled and included)
   c. 2022 system configuration (with the ASP in service)
2. Substation layout diagrams representing the Valley Substation
3. Impedance drawings for the Valley South and Valley North Systems depicting the line ratings and configurations
4. Single-line diagram of the Valley South and Valley North Systems
5. Contingency processor tools to develop relevant study contingencies to be considered for each system configuration
6. 8,760 load shape of the Valley South System
7. Advanced metering infrastructure (AMI) data for metered customers in the Valley South and Valley North Systems with circuit and substation association, annual consumption amount, and peak demand use

The reliability assessment utilizes the load forecasts developed for Valley South and Valley North System service territories to evaluate the performance of the system for future planning horizons. The developed forecasts are detailed in Section 2 of this report. The primary forecasts under consideration for reliability analysis are the Effective PV (§2.4) along with associated sensitivities, the Spatial Base Forecast (§2.4), and PVWatts (§2.4). The Effective PV forecast is expected to most closely resemble the levels of growth anticipated in the Valley South System. The developed forecasts take into consideration the variabilities in future developments of PV, EV, energy efficiency, energy storage, and LMDR.

The load forecasts for Valley South are presented in Figure 3-1, which demonstrate system deficiency in (need) year 2022 (Effective PV and PVWatts) and 2021 (Spatial Base), where the loading on the Valley South transformers exceed maximum operating limits (1,120 MVA). Figure 3-2, presents the representative load forecast for Valley North where the loading on the Valley North transformers exceed maximum operating limits (1,120 MVA) by 2045 in the Spatial Base forecast.

Benefits begin to accrue coincident with the project need year. For purposes of this assessment, it is assumed that the project will be in service by this year, and benefits accrue from the need year to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

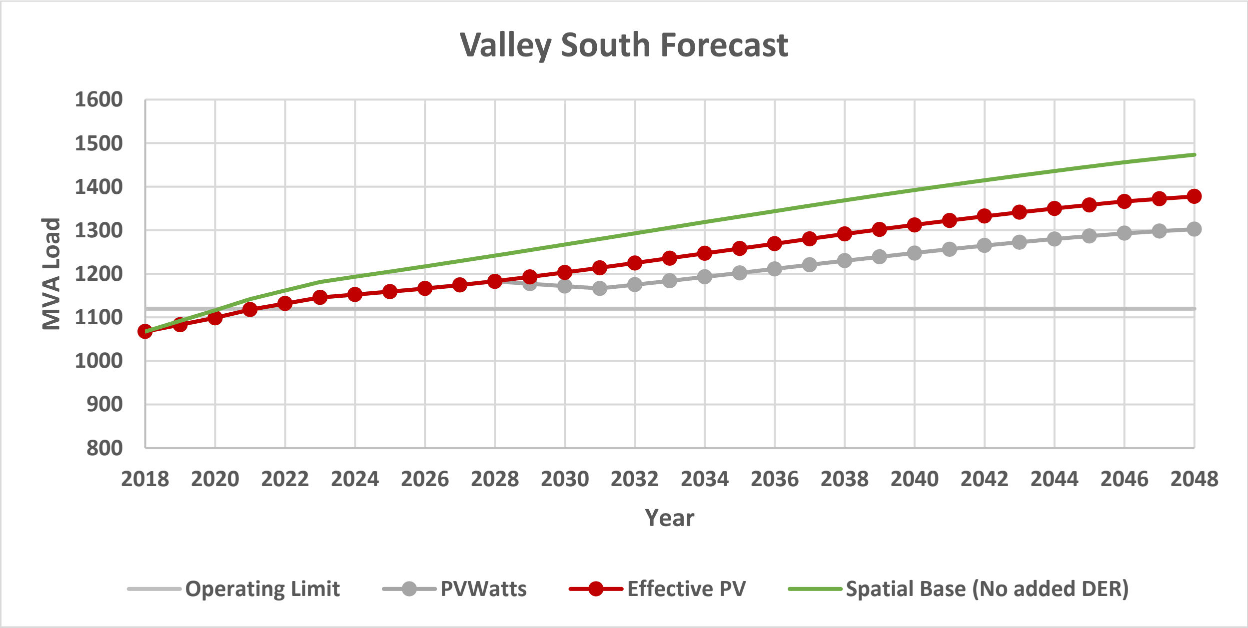


Figure 3-1. Valley South Load Forecast (Peak)

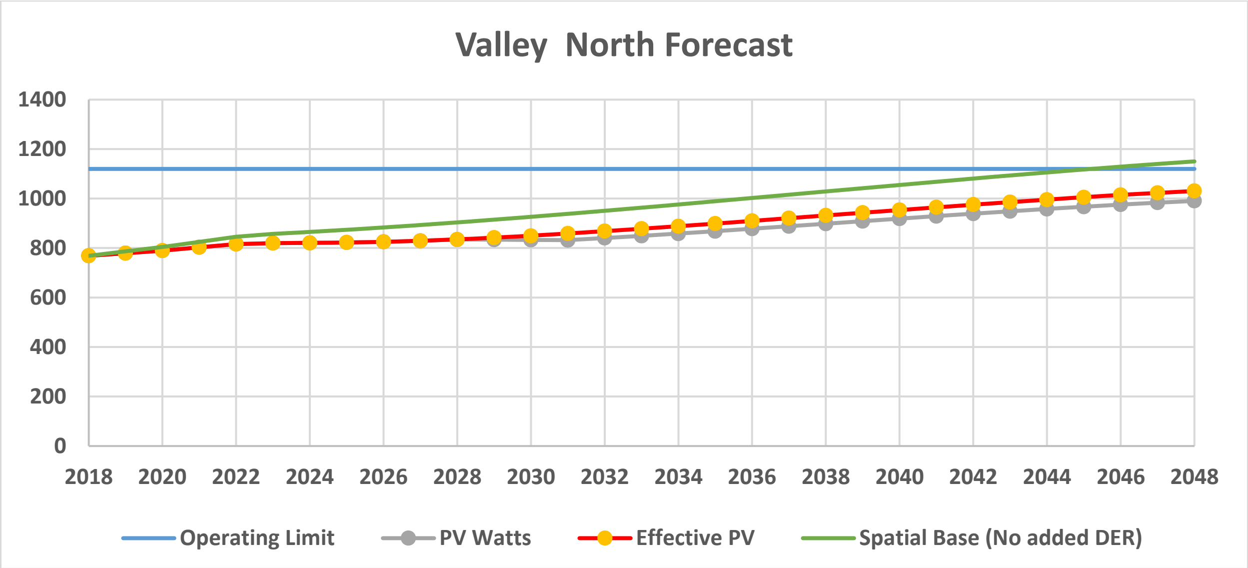


Figure 3-2. Valley North Load Forecast (Peak)

System configuration for the years 2018 (current), 2021, and 2022 are depicted in Figure 3-3 through Figure 3-5.

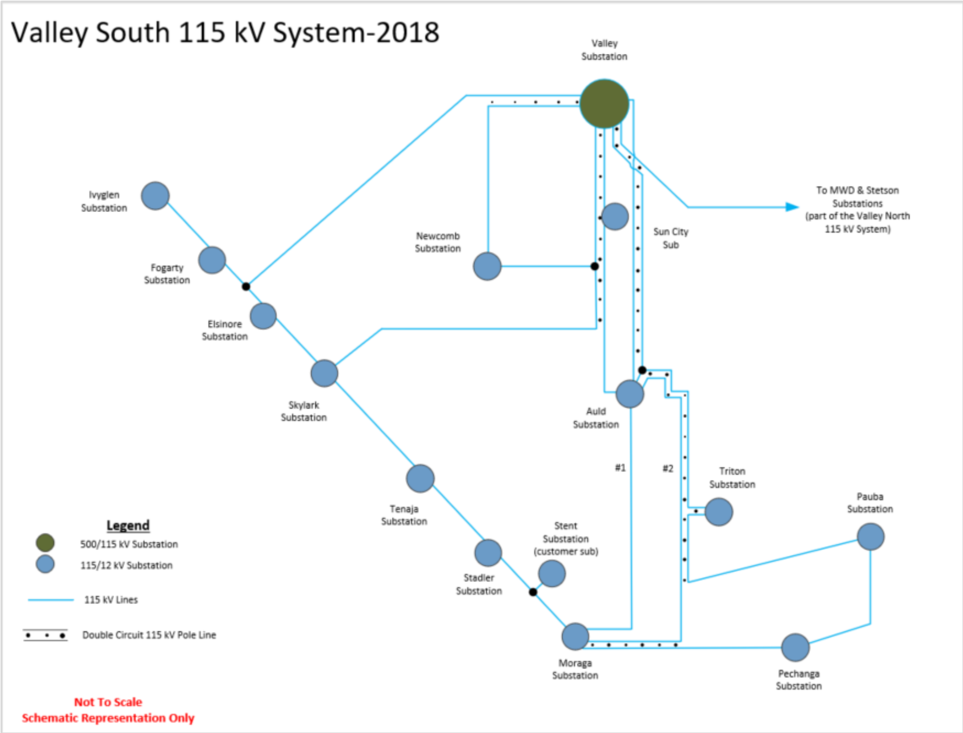


Figure 3-3. Valley South System Current Configuration (2018)

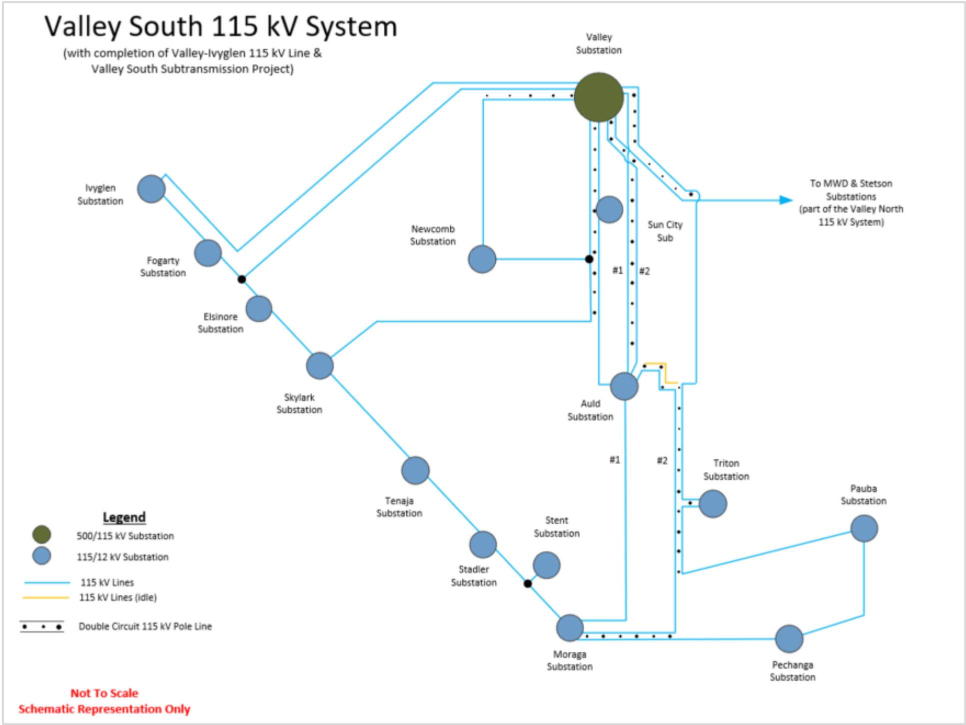


Figure 3-4. Valley South System Configuration (2021)

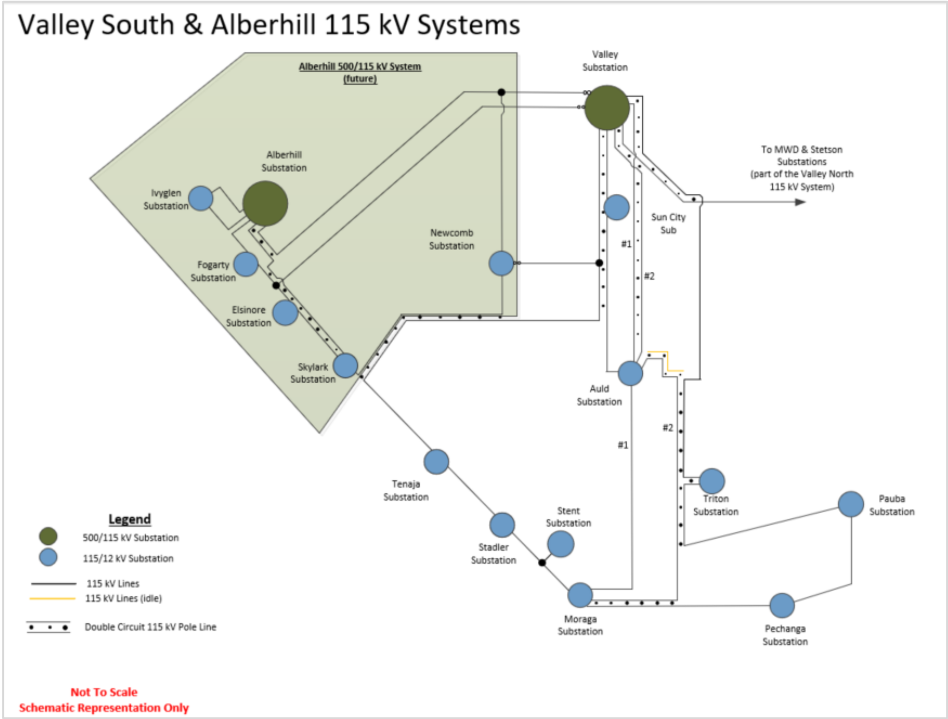


Figure 3-5. Valley South System Configuration (2022 with ASP in-service)

The load shape of the year 2016 was selected for this study. This selection was made because it demonstrated the largest variability among available records.[6] This load shape is presented in Figure 3-6.

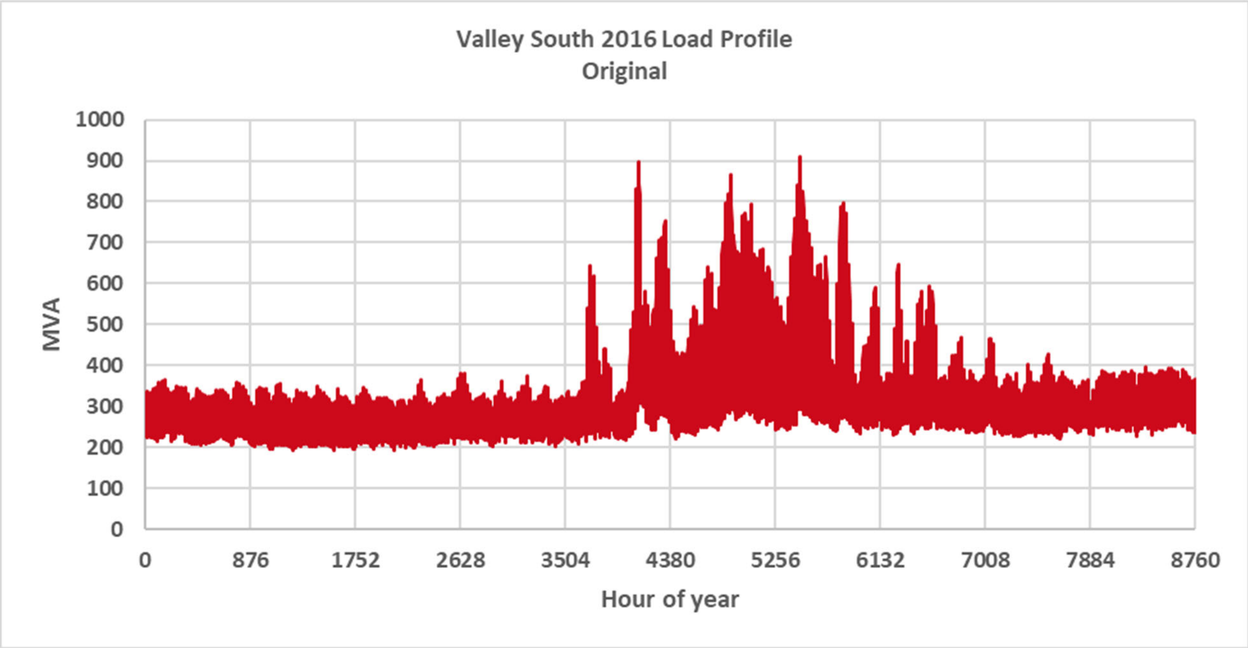


Figure 3-6. Load Shape of the Valley South System

3.2.2 Study Criteria

The following guidelines have been used through the course of this analysis to ensure consistency with SCE planning practices:

- The study and planning of projects adhered to SCE's Subtransmission Planning Criteria and Guidelines. Where applicable, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards were referenced when considering any potential impacts on the BES and the non-radial parts of the system under CAISO control.
- Transformer overload criteria established per SCE Subtransmission Planning Criteria and Guidelines for AA banks have been utilized.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.
- Voltage limits of 0.95–1.05 per unit under N-0 and N-1 operating configurations.
- Voltage deviation within established limits of ±5% post contingency.

3.2.3 Reliability Study Tools and Application

A combination of power flow simulation tools has been utilized for this analysis, such as General Electric's Positive Sequence Load Flow (PSLF) and PowerGem TARA. PSLF has been used for base-case model

[6] Note that the load shapes of years 2017 and 2018 were skewed due to the use of the AA-bank spare transformers as overload mitigation. Therefore, the load shape for year 2016 was adopted. Its shape is representative only and does not change among years.

development, conditioning, contingency development, and system diagram capabilities. TARA has been used to perform time-series power-flow analysis.

Time-series power-flow analysis is typically used in distribution system analysis to assess variation of quantities over time with changes in load, generation, power-line status, etc. It is now finding common application in transmission system analysis, especially when the system under study is not heavily meshed (radial in nature).

In this analysis, the peak load MVA of the load shape has been adjusted (scaled) to reflect the peak demand for each future year under study. This is represented by Figure 3-7 for the Valley South System as an example. The MVA peak load is then distributed amongst the various distribution substations in the Valley South System in proportion to their ratio of peak load to that of the entire Valley South System in the base case. Distribution substations under consideration in this analysis of the Valley South and Valley North Systems are listed in Table 3-1.

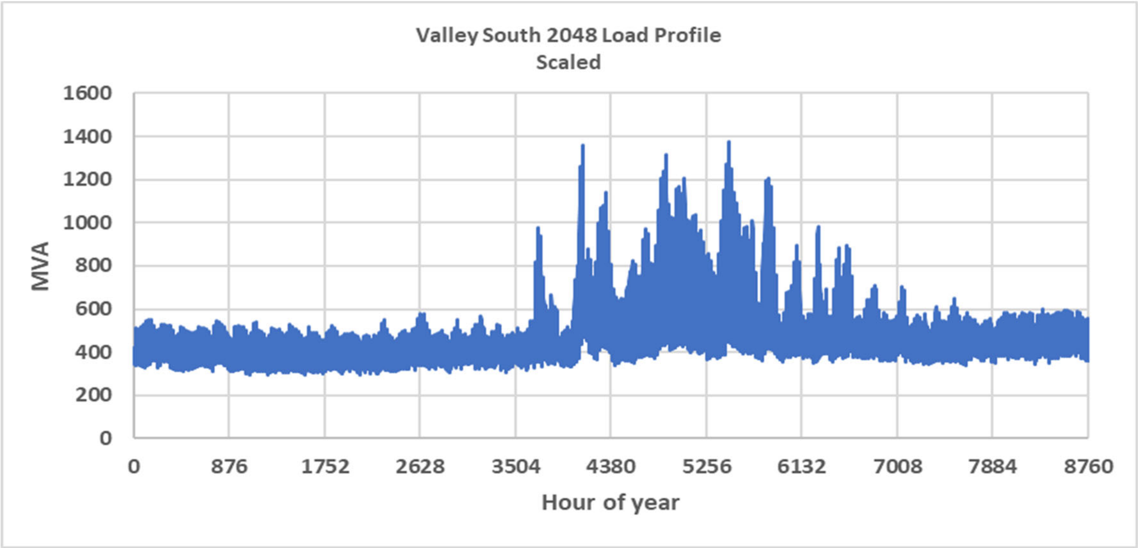


Figure 3-7. Scaled Valley South Load Shape Representative of Study Years

Table 3-1. Distribution Substation Load Buses

Valley South	Valley North
Auld	Alessandro
Elsinore	Bunker
Fogarty	Cajalco
Ivyglen	ESRP_MWD
Moraga	Karma
Newcomb	Lakeview
Pechanga	Mayberry

Valley South	Valley North
Pauba	Moreno
Skylark	Moval
Stadler	Nelson
Stent	Stetson
Sun City	
Tenaja	
Triton	

Hourly study (8,760 simulations per year) was conducted in selected years (5-year period) starting from the year 2022 or 2021 where transformer capacity need exceeds its operating limit. The results for the years in between were interpolated. At each simulation, the alternating current (AC) power-flow solution was solved, relevant equipment was monitored under N-0 conditions (using equipment ratings under normal conditions) and N-1 conditions (using equipment ratings under emergency conditions), potential reliability violations were recorded, and performance reliability metrics (as described in Section 3.2.4) were calculated. A flowchart of the overall study process is presented in Figure 3-8.

Unless otherwise specified, all calculations performed under reliability analysis compute the load at risk in MW or MWh, which is not a probability-weighted metric.

The N-1 contingency has been evaluated for every hour of the 8,760 simulations, and the outages were considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates single-circuit outages for all subtransmission lines within the system. Whenever an overload or voltage violation was observed, the binding constraint was applied to compute relevant reliability metric(s). When the project under evaluation has system tie-lines that can be leveraged, tie-lines were engaged to minimize system impacts. The losses are monitored every hour and aggregated across the existing and new transmission lines in the service area.

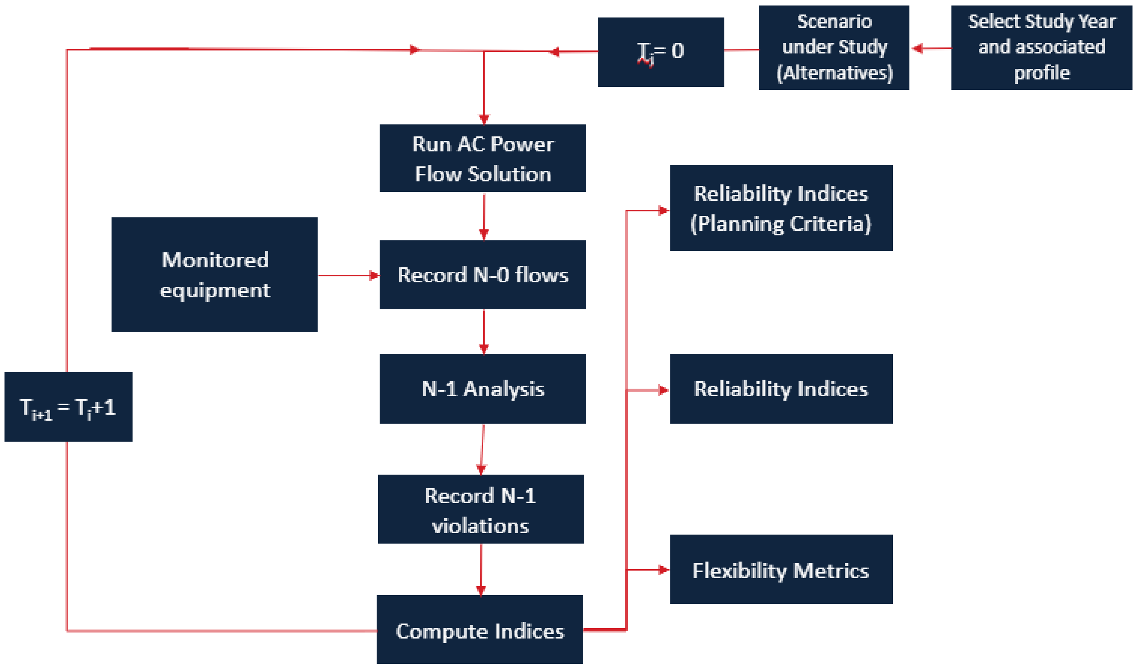


Figure 3-8. Flowchart of Reliability Assessment Process

Several operational flexibility metrics were developed to evaluate the incremental benefits of system tie-lines under emergency including planned and unplanned outages and HILP events in the Valley South System.

Flexibility Metric 1 evaluates the system under N-2 (common pole double-circuit outages) addressing combinations of two transmission lines out of service. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates double-circuit outages for all sub-transmission lines that share a common tower or right-of-way. The objective of this metric is to gauge the incremental benefits that projects provide for events that would traditionally result in unserved energy in the Valley South System. The flow chart in Figure 3-9 presents the overall process. The analysis is initiated taking into consideration the peak loading day (24-hour duration) for a year and applying the N-2 contingencies at each hour. Whenever an overload or voltage violation was observed, the binding constraint is used to determine the MWh load at risk (LAR) and to calculate the weighted amount using the associated contingency probabilities. The probability-weighted MWh is representative of the expected energy not served (EENS). The contingency probabilities were derived from a review of the historic outage data in the timeframe from 2005 to 2018 in the SCE system. The results for the peak day were compared against the baseline system and utilized as the common denominator to scale other days of the year for aggregation into the flexibility metric. During the analysis, it was observed that the system is vulnerable to N-2 events at load levels greater than 900 MW. This also corresponds to the Valley South operating limit wherein the spare transformer is switched into service to maintain transformer N-1 security. Thus, for purposes of scaling, only days with peak load greater than 900 MW were selected where there is a potential for LAR to accumulate in the system. When the project under evaluation has tie-lines, they are used to minimize system impacts.

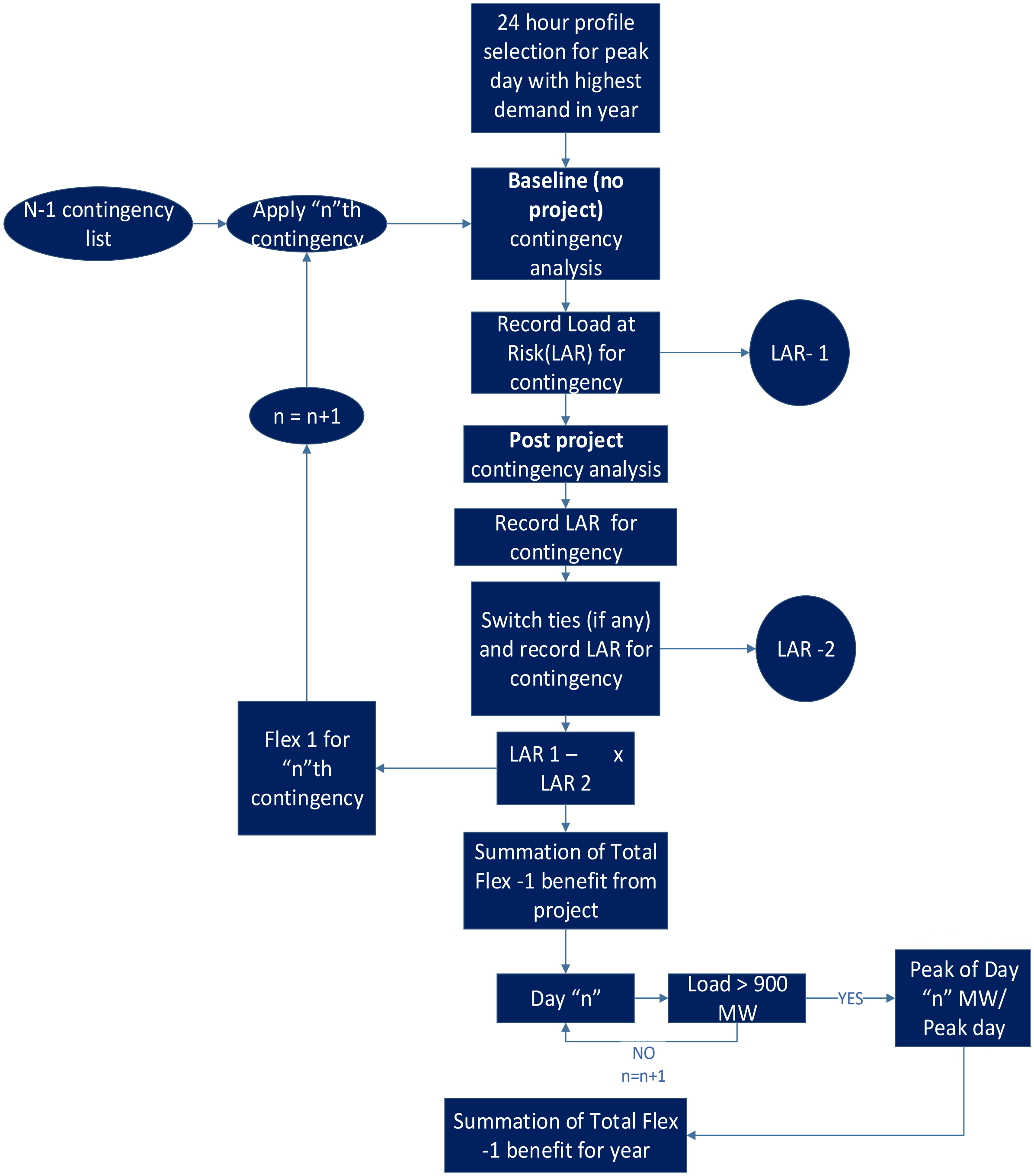


Figure 3-9. Flowchart of Flexibility Metric 1 (Flex-1) Calculation Process

Flexibility Metric 2 evaluates the project performance under HILP events in the Valley South System. This has been broken down into two components that consider different events impacting Valley South ENA. Both components utilize a combination of power flow and load profile analysis to determine the amount of LAR.

- Flexibility Metric 2-1 evaluates the impact of the entire Valley Substation out of service, wherein all the load served by Valley Substation is at risk. Considering a 2-week event (assumed substation outage duration to fully recover from an event of this magnitude), the average amount of LAR is determined. Utilizing power-flow simulations to evaluate the maximum load that can be transferred by projects using system ties, the amount of load that can be recovered is estimated.
- Flexibility Metric 2-2 evaluates a condition wherein the Valley South ENA is served by a single transformer (i.e., two load-serving transformers at Valley Substation are out of service). This scenario is a result of a catastrophic failure (e.g. fire or explosion) of one of the two transformers, and causing collateral damage to the adjacent transformer, rendering both transformers unavailable. Under these conditions, the spare transformer is used to serve a portion of the load. Utilizing the 8,760-load shape and the transformer short-term emergency loading limits (STELL) and long-term emergency loading limits (LTELL), the average amount of MWh over a 2-week duration LAR is estimated and aggregated ("mean time to repair" under major failures). The analysis accounts for the incremental relief offered by solutions with permanent and temporary load transfer using system ties.

3.2.4 Reliability Metrics

Prior to introducing reliability metrics, key elements of the overall project objectives must be outlined to provide direction and to guide further analysis. The following key concepts are revisited using applicable NERC guidelines and standards for the BES.

- Reliability has been measured with reference to equipment rating (thermal overload) and voltage magnitude (low voltages).
- Capacity represents the need to have adequate resources to ensure that the electricity demand can be met without service outages. Capacity is evaluated under normal and emergency system conditions and under normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address an emergency, maintenance, or planned outage condition. Therefore, it is expected to operate the system radially and to accommodate flexibility by employing normally open system tie-lines.
- Resilience has been viewed as an extension of the flexibility benefits, wherein system tie-lines are leveraged to recover load under HILP events.

Building on the overall project objectives, the following reliability metrics have been established to address the reliability, capacity, flexibility, and resilience needs of the system:

- **Load at Risk (LAR)**
  a. This is quantified by the amount of MWh at risk from each of the following elements:
     i. For each thermal overload, the MW amount to be curtailed to reduce loading below equipment ratings. This includes both transformers and power lines serving the Valley South system.
     ii. For voltage violations, the MW amount of load to be dropped based on the voltage sensitivity of the bus to bring the voltage to within established operating limits. The sensitivity study established ranges of load drop associated with varying levels of post-contingency voltage.

For deviations in a bus voltage from the 0.95 per unit limit, the amount of load drop to avoid the violation was determined.

b. LAR was computed for N-0 and N-1 events and aggregated or averaged over 1 year. The focus of the analysis is on the Valley South System. However, under N-0 condition, LAR recorded on the Valley North system was also accumulated during the simulation.
c. For N-1 events, system tie-lines are used where applicable to minimize the amount of MWh at risk.

- **Maximum Interrupted Power (IP)**
  a. This is quantified as the maximum amount of load in MW dropped to address thermal overloads and voltage violations. In other words, it is representative of the peak MW overload observed among all overloaded elements.
  b. IP was computed for N-0 events and N-1 events.

- **Valley South System Losses**: Losses (MWh) are treated as the active power losses in the Valley South System. New transmission lines, introduced by the scope of a project, have also been included in the loss computation.

- **Availability of Flexibility in the System**: Measure the availability of flexible resources (system tie-lines, switching schemes) to serve customer demand. It provides a proxy basis for the amount of flexibility (MWh) that an alternative project provides during maintenance operations, emergency events, or other operational issues. Two flexibility metrics are considered:
  a. Flexibility Metric 1: Capability to recover load during maintenance and outage conditions.
     i. Calculated as the amount of energy not served for N-2 events. The measure of the capability of the project to provide flexibility to avoid certain overloads and violations observable under the traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served using the flexibility attributes of the project.
  b. Flexibility Metric 2: Recover load for the emergency condition: Single point of failure at the Valley substation and its transformer banks.
     i. Flex-2-1: Calculated as the energy unserved when the system is impacted by HILP events such as loss of the Valley Substation resulting in no source left to serve the load. Projects that establish system tie-lines or connections to an adjacent network can support the recovery of load during these events. This metric is calculated over an average 2-week period (assumed minimum restoration duration for events of this magnitude) in the Valley South system.
     ii. Flex-2-2: Calculated as the amount of MWh load at risk when the system is operating with a single (spare) transformer at Valley Substation (two transformers are out of service due to major failures). This event is calculated over an average 2-week period in the Valley South System. Projects that establish system tie-lines to adjacent networks can support load recovery during these events.

- **Period of Flexibility Deficit (PFD)**: The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) was insufficient and resulted in energy not being served for a given time horizon.

The above list has been iteratively developed to successfully translate project objectives into quantifiable metrics and provides a basis for project performance evaluation.

3.3 Benefit-Cost Framework and Study Assumptions

Each of the projects has been evaluated using a benefit-cost framework that derives the value of project performance (and benefits) using a combination of methods. This framework provides an additional basis for the comparison of project performance while justifying the business case of each alternative to meet the load growth and reliability needs of the Valley South System.

The benefit is defined as the value of the impact of a project on a firm, a household, or society in general. This value can be either monetized or treated on a unit basis while dealing with reliability metrics like LAR, IP, and PFD (among other considerations). Net benefits are the total reductions in costs and damages as compared to the baseline, accruing to firms, customers, and society at large, excluding transfer payments between these beneficiary groups. All future benefits and costs are reduced to a net present worth using a discount rate and an inflation rate over the project lifetime or horizon of interest.

The overall process associated with the detailed alternatives analysis framework has been presented in Figure 3-10.

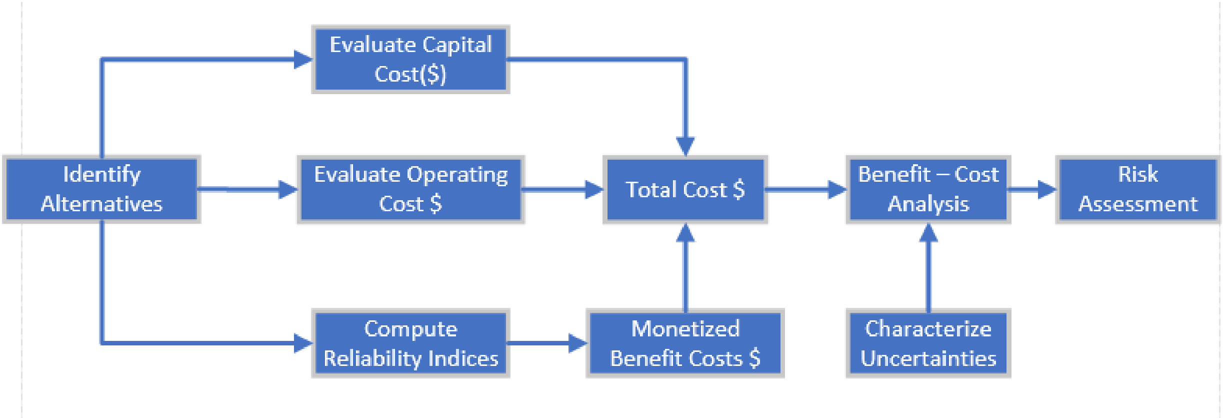


Figure 3-10. BCA Framework

The project costs have been developed by SCE as the present value of revenue requirements (PVRR) over the lifetime of the asset to include the rate of return on investment, initial capital investments, operations and maintenance (O&M), and equipment-specific costs. These are reflective of the direct costs used in the analysis. Due to the differences in equipment life of the projects under consideration, the present worth of costs has been used throughout the study horizon. The PVRR costs are offset for incremental revenues generated by the battery energy storage system (BESS) assets through market participation. Table 3-2 presents the financial assumptions considered in this analysis. Further details pertaining to each of the assumptions are presented in the upcoming sections of this report.

In the scope of this assessment, the benefits for considered metrics (Section 3.2.4) are derived by a comparison of system performance with and without the project in service. Depending on the benefit category, a distinction is made between monetized and non-monetized benefits. The monetized benefits are typically probability-weighted and represented as EENS. Unless otherwise specified, the non-monetized benefits are not probability weighted. The benefits in combination with PVRR costs have been used at different capacities to develop a comprehensive view of project performance. This evaluation framework includes a traditional benefit-cost comparison of alternatives to characterize the risks associated with load sensitivities.

Table 3-2. Financial and Operating Costs

Parameters	Value	Source
Discount rate (weighted aggregate cost of capital [WACC])	10%	SCE
Customer price (locational marginal price [LMP])	40 $/MWh	CAISO[7]
Inflation rate (price escalation)	2.5%	Quanta
Load distribution: residential	33%	SCE
Load distribution: small & medium business	36%	SCE
Load distribution: commercial and industrial	31%	SCE
Annual outage rate for Flexibility-2-2 events	0.0015	CIGRE[8]
Annual outage rate for HILP event (Flexibility-2-1 events)	0.01	NERC[9]

The non-monetized benefits have been presented in two different formats. From the perspective of reliability analysis (Sections 4 and 5), they are described as the sum (or the cumulative effect) of the benefits of the project over the project study horizon. In the cost-benefit framework (Section 6), the non-monetized benefits are calculated as the present worth of benefits discounted at the weighted aggregate cost of capital (WACC) throughout the study horizon. An example of the latter, LAR (MWh) benefits of the ASP under normal system condition (N-0) and their present worth using the discount rate of WACC are presented in Figure 3-11.

[7] http://oasis.caiso.com/ (Node: VALLEYSC_5_B1)
[8] Reference [8]
[9] Reference [7]

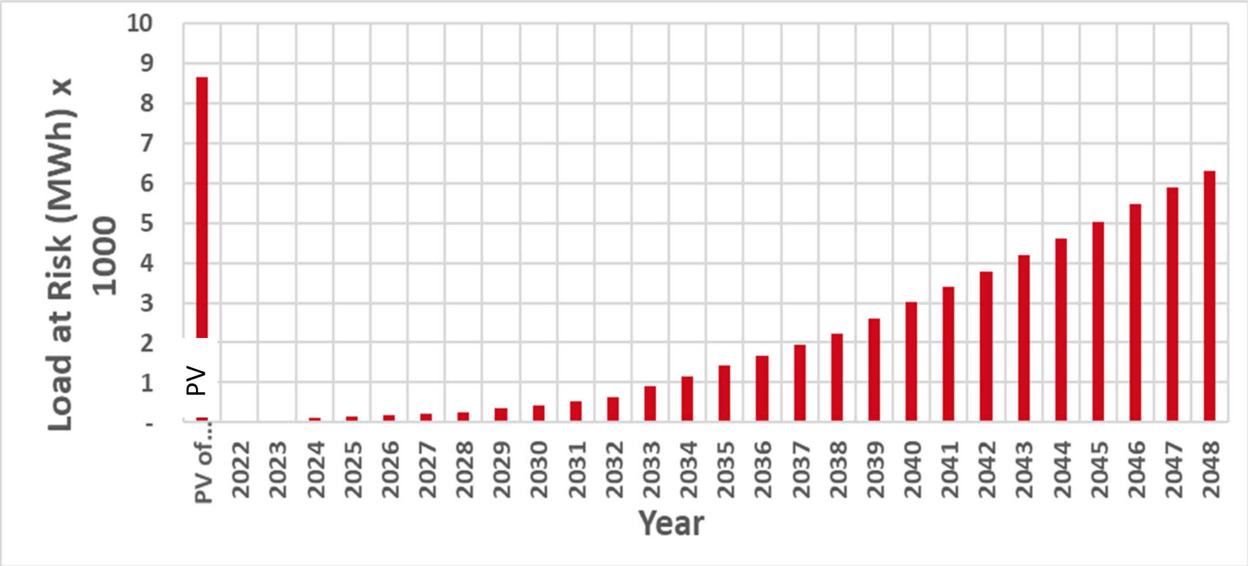


Figure 3-11. LAR (N-0) Benefits Accumulated for ASP over the Study Horizon

LAR (N-0, N-1) and flexibility indices (Flex-1, Flex-2-1, and Flex-2-2) were monetized using the $/kWh for unserved energy (load) from the customer perspective as provided by SCE [6]. These costs are separated into residential, small & medium business, and commercial & industrial in $/kWh. Figure 3-12 presents the costs over a 24-hour duration as applied to this assessment.

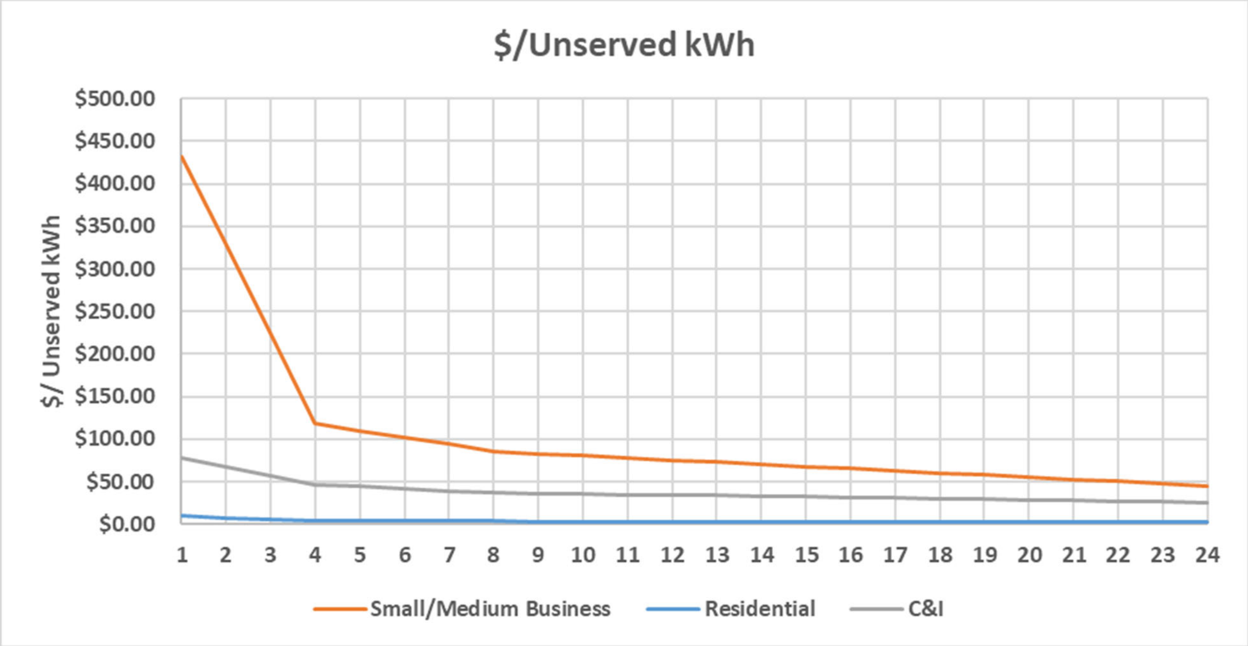


Figure 3-12. Value of Unserved kWh

The formulation below describes the monetized benefits and are complemented by the assumptions detailed previously in Table 3-2:

- EENS under N-0 conditions:
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour outage duration.
  - Costs derived from Figure 3-12 for the 1-hour outage, consistent with the principles of rolling outages between different customers each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
- EENS under N-1 conditions:
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) were used consistent with the principles of rolling outages between different customers each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities of circuit outages have been derived from historic event data in the Valley South, with a failure rate of 3.4 outages per 100 mile years and a mean duration of 2.8 hours.[10] The outage probabilities associated with N-1 circuits are presented in Table 3-3. For new lines in the alternatives, probabilities have been calculated using the estimated length of the circuit and the associated failure rates using the 3.4 outages per 100 mile-years metric.

Table 3-3. N-1 Line Outage Probabilities in Valley South

Line Name	Line Outage Probability Index
Auld-Moraga #1	0.36074
Auld-Moraga #2	0.40664
Auld-Sun City	0.27846
Elsinore-Skylark	0.1632
Fogarty-Ivyglen	0.32164
Moraga-Pechanga	0.17578
Moraga-Stadler-Stent	0.23188
Pauba-Pechanga	0.26112
Pauba-Triton	0.26622
Skylark-Tenaja	0.14994
Stadler-Tenaja	0.17374
Valley-Elsinore-Fogarty	0.59092

[10] Provided by SCE.

Line Name	Line Outage Probability Index
Valley-Newcomb	0.21454
Valley-Newcomb-Skylark	0.67966
Valley-Sun City	0.12818
Valley-Ivyglen	0.918
Valley-Auld #1	0.40664
Valley-Auld #2	0.34884
Valley-Triton	0.53244

- Flexibility-1 Metric
  - LAR (MWh) for 1 year multiplied by the cost of lost load ($/MWh) associated with a 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) are used consistent with the principles of rolling outages between different customers at each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities of circuit outages were derived from historic event data in Valley South System, with a failure rate of 0.8 outages per 100 mile years and a mean duration of 3 hours.
  - Considering the large combination of N-2 circuit outages that potentially impact the Valley South System, Flexibility 1 metrics are limited only to circuits that share a double circuit pole. The outage probabilities associated with N-2 contingencies are provided in the Appendix (Section 9).
- Flexibility-2-1 Metric
  - LAR (MWh) over an average 2-week duration multiplied by the cost of lost load ($/MWh) associated with assumed a 2-week outage duration multiplied by the outage probability.
  - The outage duration for this event is considered to be 2 weeks, reflective of the minimum restoration duration for an event of this magnitude. The cost has been derived as the average cost of lost load using hour 1 and hour 24 from Figure 3-12. Considering the uncertainties and shortage of publically available data sources to support the quantification of customer interruption costs due to events of this magnitude, the average of hour 1 and hour 24 cost data would prevent bias towards to a higher or lower monetary impact.
  - The cost associated with this event for residential is 5.68$/kWh, small/medium business is 238.4$/kWh, and commercial/industrial is 52.11$/kWh.
  - Probabilities associated with an event of this magnitude have been adopted as 0.01, signifying a 1-in-100 year event, adopted from NERC treatment of events of similar magnitude [7].
- Flexibility-2-2 Metric
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) were used consistent with the principles of rolling outages between different customers each hour.

- The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
- Probabilities associated with this event have been adopted from the CIGRE Transformer Reliability Survey [8] data for major transformer events (fire or explosion) reported to be 0.00075 failures per transformer year.

- Losses
  - Losses (MWh) for the year multiplied by the average locational marginal price (LMP) at the Valley 500-kV substation.
  - The average LMPs are obtained from production simulation of the CAISO model for the year 2021 and 2022 and escalated each year.
  - The loss reduction is treated as a benefit and aggregated to the monetized EENS and Flex benefits.

3.3.1 Benefit-Cost Methodology

As described in earlier sections of this report, all costs and benefits have been evaluated over the study horizon from the in-service year 2021/2022 (depending on the need year from forecast used for the study) to 2048, which covers the 30-year horizon. The benefits associated with each project have been calculated as the present worth of each benefit category.

Following the quantification of the present worth of costs and benefits, three different types of analysis have been considered to select the most suitable project among the pool of alternatives. The proposed methodologies utilize the benefits in their non-monetized and monetized representation.

3.3.1.1 Benefit-Cost Analysis (BCA)

The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. However, it requires both benefits and costs to be treated on a common unit basis ($). Due to this, only monetized benefits are considered for this assessment. With the monetized benefits, a ratio is derived from the cost of the project to aggregate benefits introduced by the project.

The relevant benefit categories are monetized per the discussion in Section 3.3.1. The benefits are derived as differences in monetized costs with and without the project in service, which directly translates into cost savings from the customers' perspective. For example, without a project in service, customers in the Valley South system are vulnerable to 50 MWh of EENS in the year 2026 under normal system conditions (N-0), which translates into a $6.6M cost to customers. However, with a project such as ASP in service, the 50 MW of EENS is eliminated, and the $6.6M cost to customers will be avoided.

3.3.1.2 Levelized Cost Analysis

This evaluation is most suited for non-monetized metrics and their benefit evaluation. For each of the projects under consideration:

- The benefits have been quantified using the difference between the project and the baseline scenario.
- The benefits of each category from N-0 and N-1 are normalized as the ratio of $/unit benefit using their present worth over the horizon using the WACC discount rate.

- This index primarily provides insight into the investment value ($) from each project to achieve a unit of benefit improvement from baseline.

For example, the present worth of the ASP project cost is $474M, and the present worth of N-0 EENS benefit from the ASP (in comparison to baseline) is 8,657 MWh. The ratio of $474M/8,657 MWh suggests that this project would require an investment of $54,753 to achieve 1 MWh of N-0 EENS benefit.

3.3.1.3 Incremental BCA

Incremental BCA is used to rank and value the overall benefits attributed to an alternative project while providing an advantage to the most cost-effective solution that provides maximum benefit. The procedure is summarized below [9]:

Considering that the proposed project solutions are mutually exclusive alternatives (MEA), the MEAs are ranked based on their cost in increasing order. The do-nothing or least-cost MEA is selected as the baseline. The incremental benefit-to-cost ratio $\left(\frac{\Delta B}{\Delta C}\right)$ for the next least-expensive alternative is evaluated. Provided that the ratio is equal to or above unity, this alternative will be selected and replaces the baseline to evaluate the next least-expensive MEA. For a ratio below unity, the last baseline alternative is maintained. The incremental BCA will continue and iterate between the baseline and the next alternative. The selection will stop once the incremental benefit-to-cost ratio becomes unfavorable or the list is exhausted. The flowchart in Figure 3-13 provides an overview of the overall process.

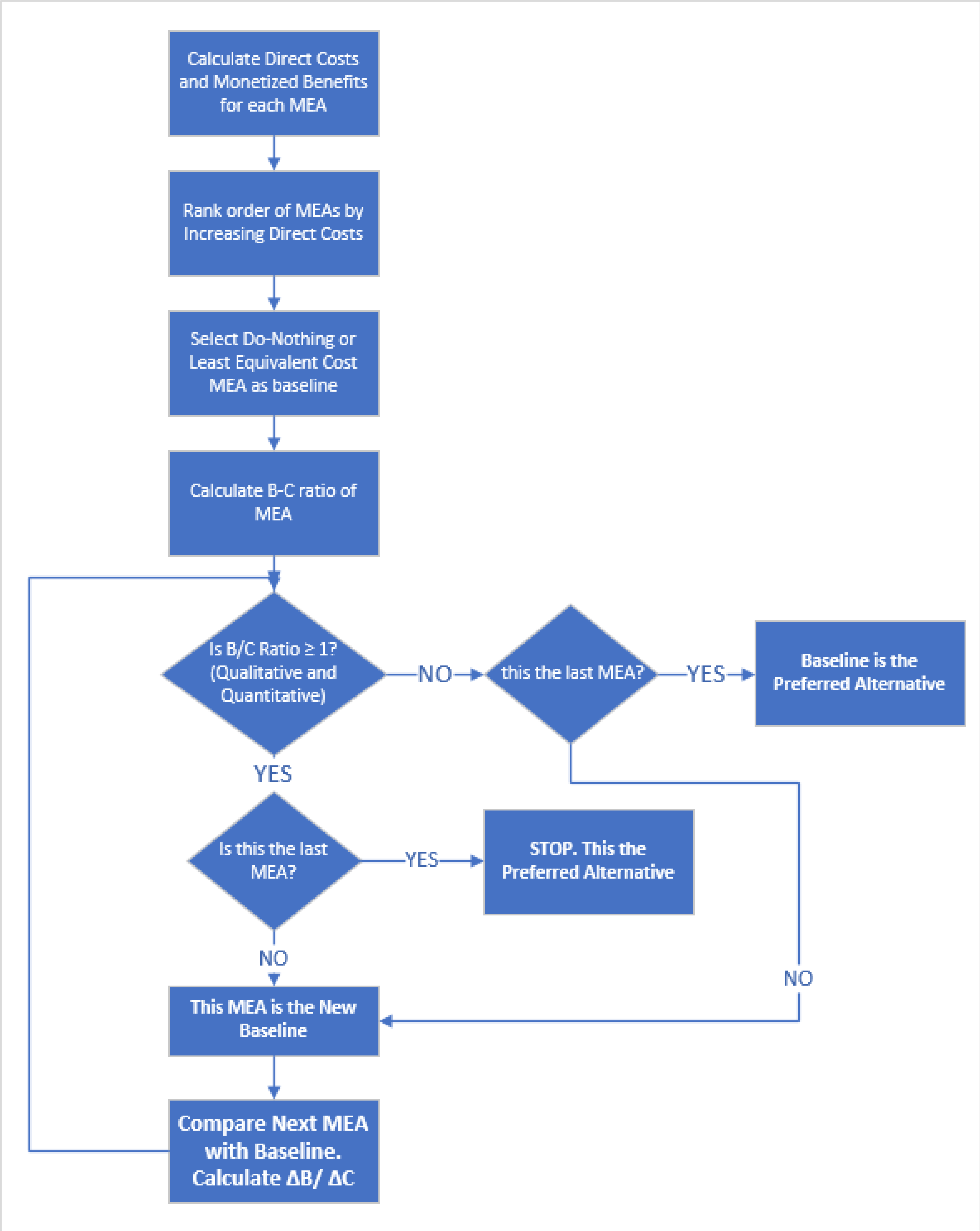


Figure 3-13. Incremental BCA Flowchart

Incremental BCA, also known as marginal benefit-to-cost analysis (MBCA), is considered a superior approach relative to a conventional BCA, for utilities to compare the cost effectiveness of alternative projects. The methodology assures "that dollars will be spent one at a time, with each dollar funding the project that will result in the most reliability benefit, resulting in an optimal budget allocation that identifies the projects that should be funded and the level of funding for each. This process allows service quality to remain as high as possible for a given level of funding—allowing electric utilities to be competitive, profitable, and successful in the new environment of deregulation" [10].

3.3.2 BESS Revenue Stacking

Revenue stacking describes a situation where a BESS is used for more than one domain of applications. When wholesale market applications and transmission and distribution (T&D) applications are allowed to be performed by the same BESS, the BESS accesses and participates in wholesale markets in addition to its primary function (T&D applications). T&D applications always take priority over wholesale market participation. This means, the function of the BESS always first ensures reliable operation of the T&D system as needed before consideration for market participation. Needed capacity and required dispatch levels must be considered as constraints to market participation.

In the Valley South planning area, batteries primarily provide local reliability, capacity, and flexibility benefits by supporting N-0, N-1, and N-2 needs in the system (primary application). To leverage the benefits from BESS-based solutions in each of these categories, the available capacity is reserved during summer months (peak demand period) from June to October (i.e., the BESS is only allowed to participate in the wholesale market outside the summer operating period).

When the BESS is not required for the primary application, it can time-shift the energy by participating in wholesale energy markets (i.e., market participation). This service results in ratepayer savings when the asset is assumed to be utility-owned with all energy cost savings passed on to ratepayers. "Shared application" or "hybrid application" is also investigated. This means that the storage is also used for ancillary services provision.

For applicable solutions that include BESS (NWAs or hybrid), additional potential benefits of BESS participating in CAISO wholesale and ancillary service (AS) markets are determined. The optimization uses the day-ahead (DA) prices for charging and discharging to simulate the strategy in which charging load and discharging are offered into the DA market. For this purpose, 2018–2019 DA for the node at the Valley South System is used. Energy storage also offers regulation-up (RegUp) and regulation-down (RegDown) services into the CAISO AS markets. Each day, the optimization would co-optimize the energy and AS participation across the day to maximize revenues subject to BESS operational constraints.

An energy credit is calculated under each scenario using the discharging revenues less the charging payments when only wholesale energy participation is considered. These energy credits in the wholesale and regulation cases also include an estimate of the settlement of regulation revenues at AS clearing prices. Generally, energy credits decrease as regulation capacity increases, as less battery capacity is then available for arbitrage. Table 3-4 summarizes data inputs that have been utilized for market analysis. This includes the data name, data type, and duration of the extracted data (applicable for time-series data).

Table 3-4. Data Inputs for Market Analysis

Input Name	Input Data Type (Source)	Value
Hourly Load Data (MW)	Time-series (SCE)	Data provided for 01/01/2016 – 01/01/2017
Load Threshold (MW)	Parameter (SCE)	1120 MW
Battery Variable O&M Cost ($/kWh)	Parameter (QTech)	0.005 $/kWh
Battery Min/Max Allowable State of Charge (SOC)	Parameter (QTech)	Min/Max: 5/100%
Start/End of Day SOC	Parameter (QTech)	50%
BESS Charging Efficiency	Parameter (QTech)	92%
Wholesale Day-Ahead LMP Data ($/kWh)	Time-series (ISO)	Data extracted for 01/01/2018 – 01/01/2019
BESS Discharging Efficiency	Parameter (QTech)	98%
Regulation Up and Down Clearing Market Prices ($/kW)	Time-series (ISO)	Data extracted for 01/01/18 – 01/01/2019
LMP Price Escalation/yr	Time-series (QTech)	2.5%
LA Basin Local RA Weighted Average Value ($/kW-Month)	Parameter (CPUC [11])	3.64/kW – Month for year 2018

This evaluation was carried out using a proprietary optimization tool developed by Quanta Technology. The tool uses a mixed-integer programming methodology. The co-optimization of storage resource participation in energy and AS markets is similar to that performed by the CAISO in its market-clearing. The tool computes the optimal allocation of BESS capacity to the different markets each hour while observing constraints imposed by the BESS characteristics and capabilities. This is done for the 8,760 hours of the year and the total revenues computed.

For the storage sizes established under each project, a bidding strategy of offering both charging and discharging into the DA markets was evaluated. As an additional step, the strategy of also offering RegUp and RegDown services into the CAISO AS markets was evaluated. Each day, the optimization would co-optimize the energy and AS participation across the day to maximize revenues subject to BESS operational constraints. The prices were escalated at 2.5%/yr to cover the horizon until 2048. Annual market benefits are calculated as a summation of energy, RegUp, and RegDown capacity less the variable O&M. Note: the variable O&M of $0.00579/kWh is considered for both charging and discharging of the battery. A low-order variable O&M cost is assumed to account for external costs including bidding, scheduling, metering, and settlement. Figure 3-14 exhibits a sample from the optimized BESS schedule over a 24-hour duration.

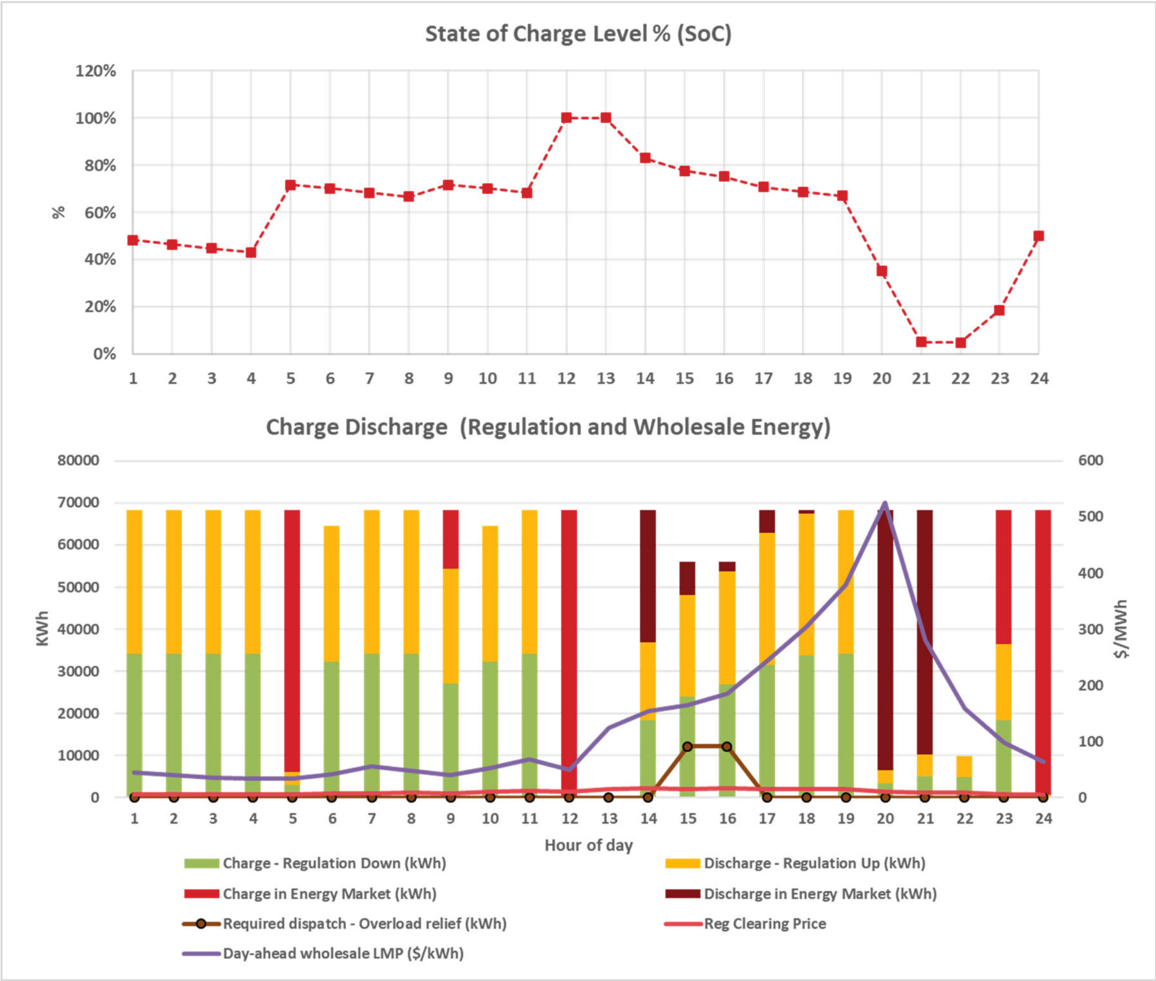


Figure 3-14. Daily Scheduling Example

In addition to participation in wholesale energy and AS markets, potential revenue available from the Resource Adequacy (RA capacity markets) have been estimated. The revenues are derived using local RA prices for the Los Angeles basin area obtained from the CPUC 2018 Resource Adequacy Report [11].

The model assumes available capacity is reserved during summer months (peak demand period) from June to October (i.e., the BESS is only allowed to participate in the RA market outside the summer operating period). The RA prices representative of the weighted average values has been used and escalated at a rate of 2.5% for future years. The analysis takes into consideration the minimum 4-hour duration requirement for BESS participation while accounting for capacity fading at a rate of 3% per year.

3.3.3 Risk Assessment

Load forecast uncertainty has been treated in the risk assessment. The range of load variability associated with the three main forecasts considered in this study are presented in Figure 3-15 and Table 3-5.

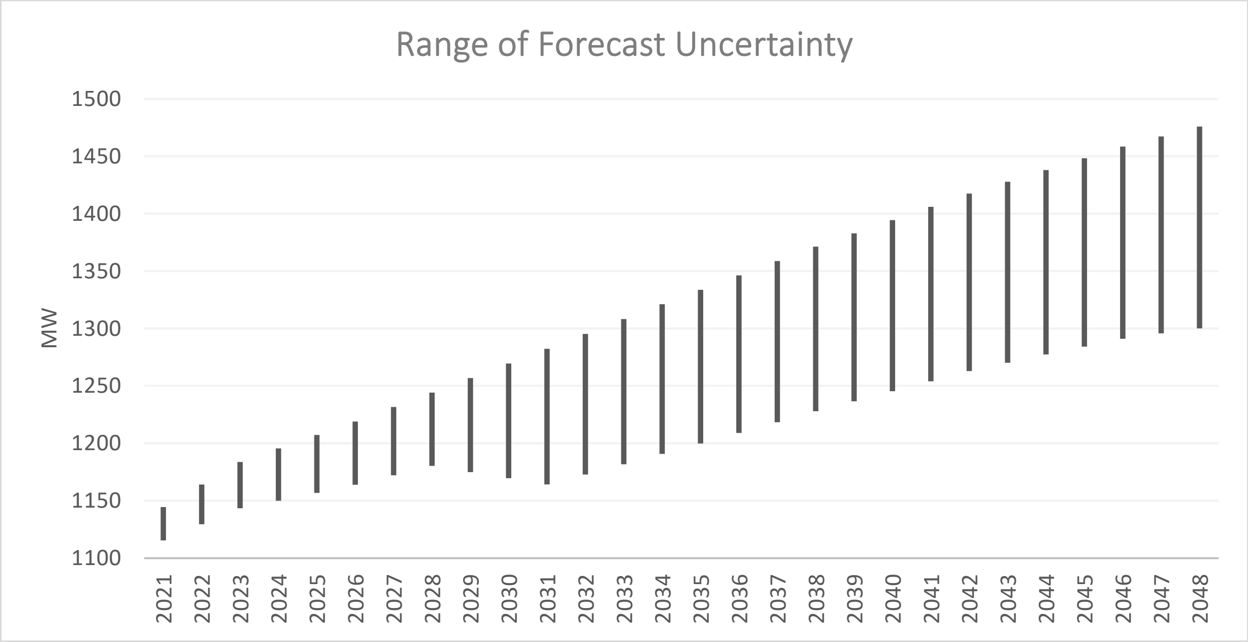


Figure 3-15. Load Forecast Range

Table 3-5. Statistics Associated with Load Forecast

Year	Low (MW)	High (MW)
2023	1146	1181
2028	1183	1242
2038	1230	1369
2048	1302	1474

Considering the spectrum of alternative projects under analysis, a deterministic risk analysis has been performed. The deterministic risk analysis provides insight into the capabilities of alternatives to meet the incremental demands of the system in the future and characterizes the risks associated with load sensitivities. Within the scope of the deterministic risk analysis, the performance of project alternatives is investigated under various forecast trends and compared using benefit-cost metrics.

4 RELIABILITY ASSESSMENT OF ALBERHILL SYSTEM PROJECT

4.1 Introduction

The objective of the analysis in this section is to apply the reliability assessment framework to the ASP. The performance and benefits of the ASP are computed in comparison to the baseline scenario (i.e., no project in service) following the methodology detailed in Section 3.2. The performance of the baseline system is initially presented, followed by the ASP for all considered load forecasts (PVWatts, Effective PV, and Spatial Base).

In order to successfully evaluate the benefits of potential projects in the Valley South System, the performance of each project must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance
2. To compare project performance to the baseline scenario (no project in service)
3. To establish a basis to value the performance of the ASP against overall project objectives
4. To take into consideration the benefits or impacts of flexibility and resilience (HILP events)
5. To guide for comparing projects against alternatives

Within the framework of this analysis, the reliability, capacity, flexibility, and resilience benefits have been quantified.

4.2 Reliability Analysis of the Baseline System

The baseline system is the no-project scenario within this analysis. It depicts a condition wherein the load grows to levels established by the forecast under the study, without any project in service to address the shortfalls in transformer capacity. This scenario forms the primary basis for comparison against alternatives performance to evaluate the benefits associated with the project.

The baseline system has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

4.2.1 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions in the system are presented in Table 4-1 for the Effective PV Forecast, Table 4-2 for the Spatial Base Forecast, and Table 4 -3 for the PVWatts Forecast.

Table 4-1. Baseline N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	22	13	2	49,667
2028	250	65	7	52,288
2033	905	120	18	54,472
2038	2,212	190	37	56,656
2043	4,184	246	53	58,840
2048	6,310	288	77	61,024

Table 4-2. Baseline N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	50	22	4	50,082
2022	129	42	5	50,888
2028	908	131	19	54,467
2033	2,844	205	42	57,450
2038	5,741	280	69	60,432
2043	9,888	348	102	63,415
2048	14,522	411	142	66,397

Table 4-3. Baseline N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	22	13	2	49,667
2028	250	65	7	52,288
2033	292	67	8	52,859
2038	740	117	14	54,310
2043	1,504	155	26	55,761
2048	2,659	199	37	57,211

4.2.2 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 4-4 for the Effective PV Forecast, Table 4-5 for the Spatial Base Forecast, and Table 4-6 for the PVWatts Forecast.

Table 4-4. Baseline N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	10	2	14	54,545	127,935	2,138
2028	67	11	32	163,415	133,688	2,774
2033	249	21	54	254,140	139,702	3,514
2038	679	35	88	344,864	145,991	4,421
2043	1,596	45	120	435,589	151,619	5,294
2048	2,823	68	153	526,314	155,733	5,975

Table 4-5. Baseline N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	18	4	18	54,545	129,095	2,255
2022	40	6	28	~~122,681~~87,602	131,322	2,491
2028	231	23	60	~~531,497~~285,950	140,388	3,612
2033	989	40	98	~~872,176~~451,239	147,622	4,670
2038	2,435	62	147	~~1,212,856~~616,529	154,744	5,811
2043	5,~~263~~599	71	204	781,818~~1,553,536~~	161,142	6,952
2048	~~9,236~~10,024	128	261	~~1,894,216~~947,107	166,580	8,000

Table 4-6. Baseline N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	10	2	14	54,545	127,935	2,138
2028	67	11	32	122,681	133,688	2,774
2033	75	11	33	531,497	133,840	2,791
2038	182	20	51	872,176	139,065	3,432
2043	454	29	79	1,212,856	143,845	4,110
2048	805	35	94	1,553,536	147,226	4,615

In the baseline system analysis, the following constraints (Table 4-7) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 4-7, only thermal violations associated with each constraint are reported.

Table 4-7. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	Base case	2021	2022	2022
Auld to Moraga #1	N-0	Base case	2038	2047	
Valley EFG to Tap 39	N-0	Base case	2043		
Valley EFG to Sun City	N-0	Base case	2043		
Auld-Moraga #2	N-1	Auld-Moraga #1	2032	2038	2048
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG -Newcomb-Skylark	2033	2043	
Tap 39-Elsinore	N-1	Valley EFG -Newcomb-Skylark	2028	2038	2043
Auld-Moraga #1	N-1	Skylark-Tenaja	2038	2048	
Valley EFG-Sun City	N-1	Skylark-Tenaja	2048		
Moraga-Tap 150	N-1	Skylark-Tenaja	2048		
Skylark-Tap 22	N-1	Valley EFG -Elsinore-Fogarty	2028	2033	2038
Valley EFG-Sun City	N-1	Valley EFG -Auld #1	2038	2043	
Valley EFG-Auld #2	N-1	Valley EFG -Auld #1	2048		
Valley EFG-Auld #1	N-1	Valley EFG -Sun City	2038	2048	
Valley EFG-Auld #2	N-1	Valley EFG -Sun City	2043		
Valley EFG-Tap 22	N-1	Valley EFG -Newcomb	2038	2043	
Valley EFG-Auld #1	N-1	Valley EFG -Auld #2	2038	2048	
Valley EFG-Sun City	N-1	Valley EFG-Auld #2	2038	2043	
Valley EFG-Triton	N-1	Moraga-Pechanga	2043	-	
Valley EFG-Tap 39	N-1	Valley EFG -Ivyglen	2048	-	
Auld-Moraga #1	N-1	Valley EFG-Triton	2032	2043	2048
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2038	2043
Valley EFG-Auld #1	N-1	Valley EFG-Triton	2048		
Valley EFG-Sun City	N-1	Valley EFG-Triton	2043		

4.2.3 Key Highlights of System Performance

The key highlights of system performance for the baseline system are as follows:

1. Without any project in service, the Valley South System transformers are projected to overload in the year 2022. Sensitivity scenario using Spatial Base forecast demonstrates a need year by 2021.
2. In the Effective PV forecast by the year 2028, 250 MWh of LAR is observed in the system under N-0 conditions. This extends to 6,309 MWh by 2048 with no project in service. Through the range of forecast sensitivities, the potential LAR ranges from 2,600 MWh to 14,500 MWh in a 30-year horizon.
3. In the Effective PV forecast between 2028 and 2048, the flexibility deficit in the system increases from 7 hours to 77 hours under the N-0 condition. Considering the range of forecast uncertainties, the number of hours of deficit in the system under N-0 range from 37 hours to 147 hours in the year 2048.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasingly challenging to maintain system N-1 security.
5. In the Effective PV forecast by the year 2028, 67 MWh of LAR is observable in the system under N-1 conditions. This extends to 2,800 MWh by 2048 with no project in service. Through the range of forecast sensitivities, the potential LAR ranges from 805 MWh to ~~9,200~~10,000 MWh in a 30-year horizon.

4.3 Reliability Analysis of the Alberhill System Project (Project A)

The ASP has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

4.3.1 Description of Project Solution

The ASP would be constructed in Riverside County and includes the following components:

1. Construction of a new 1,120 MVA 500/115 kV substation to increase the electrical service capacity to the area currently served by the Valley South 115 kV system. Two transformers were installed, one of which is a spare.
2. Construction of two new 500 kV transmission line segments to connect the new substation to SCE's existing Serrano–Valley 500 kV transmission line.
3. Construction of new 115 kV subtransmission lines and modifications to existing 115 kV subtransmission lines to transfer five existing 115/12 kV distribution substations (Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb) currently served by the Valley South 115 kV System to the Alberhill 115 kV system.
4. Installation of telecommunications improvements to connect the new facilities to SCE's telecommunications network.

Figure 4-1 presents an overview of the project layout and schematic.

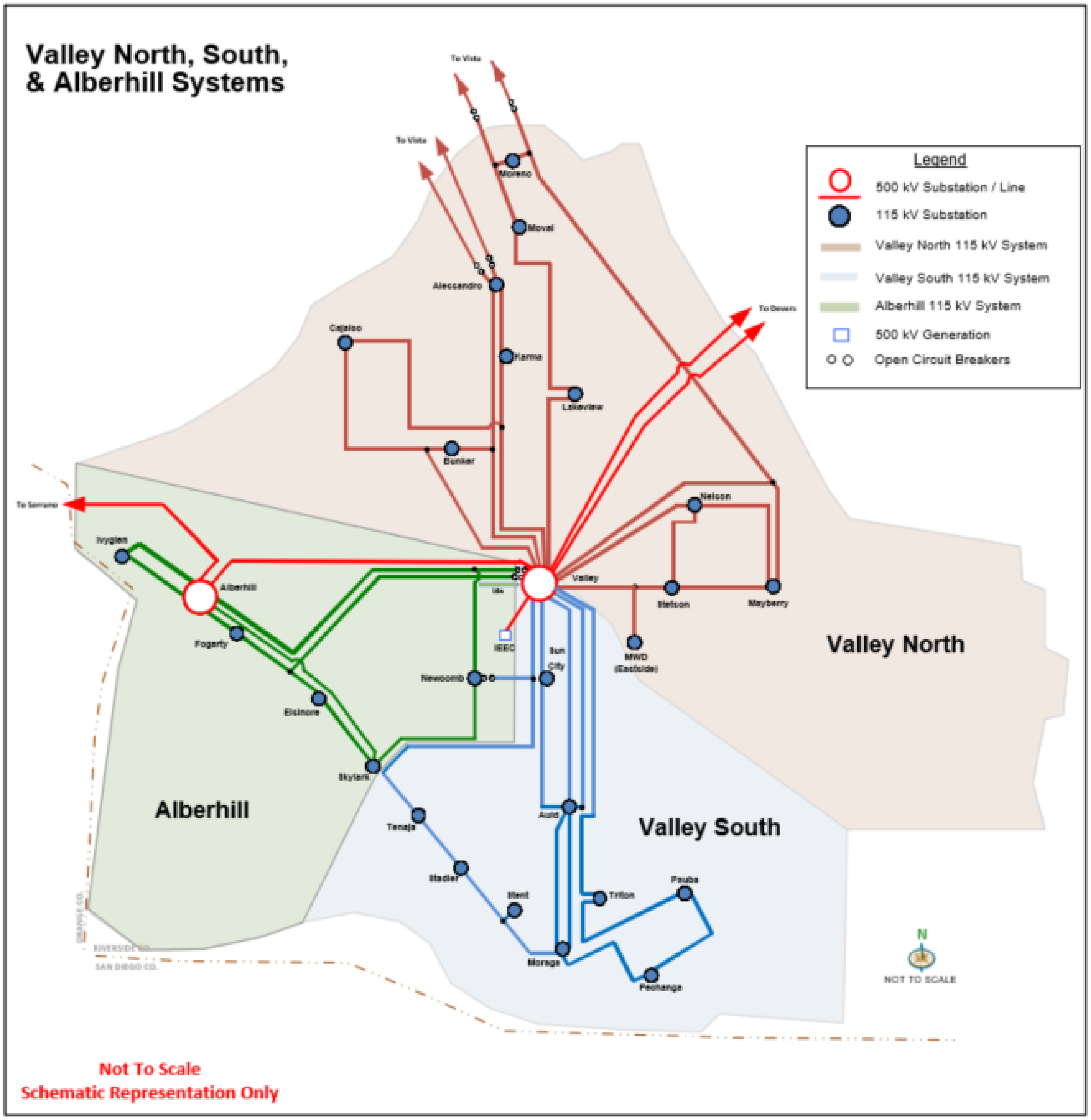


Figure 4-1. Alberhill System Project and Resulting Valley North and South Systems

4.3.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 4-8 for the Effective PV Forecast, Table 4-9 for the Spatial Base Forecast, and Table 4-10 for the PVWatts Forecast.

Table 4-8. Alberhill N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	40,621
2028	0	0	0	42,671
2033	0	0	0	44,380
2038	0	0	0	46,089
2043	0	0	0	47,797
2048	3	2	2	49,506

Table 4-9. Alberhill N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	40,954
2022	0	0	0	41,590
2028	0	0	0	43,417
2033	0	0	0	44,939
2038	1	1	1	46,462
2043	28	8	6	47,984
2048	93	14	10	49,506

Table 4-10. Alberhill N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	40,621
2028	0	0	0	42,671
2033	0	0	0	42,310
2038	0	0	0	43,725
2043	0	0	0	45,140
2048	0	0	0	46,555

4.3.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 4-11 for the Effective PV Forecast, Table 4-12 for the Spatial Base Forecast, and Table 4-13 for the PVWatts Forecast.

Table 4-11. Alberhill N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	~~22,815~~0	1163	0
2028	0	0	0	~~49,088~~30,438	1516	0
2033	0	0	0	~~70,982~~56,720	1947	0
2038	21	8	4	~~92,876~~83,001	2452	0
2043	84	17	8	~~114,770~~109,283	2954	1
2048	202	24	14	136,664	3345	4

Table 4-12. Alberhill N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~22,815~~0	1,229	-
2022	0	0	0	~~31,087~~11,530	1,363	-
2028	0	0	0	~~80,717~~80,713	1,999	-
2033	33	11	5	138,365~~122,076~~	2,593	-
2038	163	22	12	196,017~~163,435~~	3,249	3
2043	530	34	6	253,669~~204,794~~	3,896	11
2048	1,080	43	43	311,321~~246,153~~	4,494	27

Table 4-13. Alberhill N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	~~22,815~~0	1,163	0
2028	0	0	0	~~28,718~~11,254	1,516	0
2033	0	0	0	~~33,638~~20,632	1,526	0
2038	0	0	0	30,011 ~~38,557~~	1,899	0
2043	7	4	2	39,389 ~~43,476~~	2,272	0

2048	30	10	5	48,395	2,559	0

In analyzing the ASP, the following constraints (Table 4-14) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 4-14, only thermal violations associated with each constraint are reported.

Table 4-14. List of ASP Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Alberhill-Fogarty	N-0	N/A (base case)	2038	2046	-
Auld – Moraga #1	N-0	N/A (base case)	2048		
Valley EFG – Sun City	N-0	N/A (base case)	2048		
Alberhill-Fogarty	N-1	Alberhill-Skylark	2033	2038	2043
Alberhill-Skylark	N-1	Alberhill–Fogarty	2038	2043	-
Auld-Moraga #1	N-1	Valley EFG-Newcomb-Tenaja	2038	2048	-
Alberhill-Fogarty	N-1	Alberhill-Newcomb-Valley EFG	2048	-	-

4.3.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the ASP to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 4-15 for the three forecasts.

Table 4-15. Cumulative Benefits – Alberhill System Project

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	275,699	277,608	362,676
N-1	LAR (MWh)	6,282	20,~~339~~327	~~66,742~~69,479
N-1	IP (MW)	428	601	954
N-1	PFD (hr)	1,300	1,907	3,277
N-1	Flex-1 LAR (MWh)	3,901,429	~~5,688,618~~6,024,126	~~23,517,096~~9,664,642

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-1	Flex-2-1 LAR (MWh)	3,657,700	3,779,849	4,101,527
N-1	Flex-2-2 LAR (MWh)	87,801	106,937	141,992
N-0	LAR (MWh)	22,751	56,575	140,566
N-0	IP (MW)	2,713	4,053	6,213
N-0	PFD (hr)	411	811	1,559

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the ASP. The robustness of the project is justified through benefits accrued across all forecast sensitivities. The results for each category of benefits demonstrate the merits of the ASP to complement the increasing reliability, capacity, flexibility, and resilience needs in the Valley South service area.

4.3.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the ASP in service, overloading on the Valley South System transformers is avoided over the study horizon. This trend is observable across all considered forecasts. 3 MWh of LAR is recorded under N-0 condition (Effective PV Forecast) in the year 2048 due to an observed overload of the Alberhill–Fogarty 115 kV line. Across all sensitivities, the benefits range between 22.7 and 140.5 GWh of avoided LAR.
2. Considerable reduction in N-1 overloads is observed in the near-term and long-term horizons for all forecasts. With the ASP in service, the N-1 benefits in the system range from 6.2 to 66.7 GWh through all forecasts. In the Effective PV Forecast by the year 2038, overloads due to N-1 events are observed on the Alberhill–Fogarty 115 kV line, the Alberhill–Skylark 115 kV line, and the Auld–Moraga 115 kV line.
3. The project provides significant flexibility to address planned, unplanned, or emergency outages throughout the system while also providing significant benefits to address needs under HILP events that occur in the Valley South System. The ASP addresses the full range of flexibility needs identified by the baseline system across all forecast sensitivities.
4. Following a HILP event, the ASP can recover approximately 400 MW of load in Valley South leveraging capabilities of its system tie-lines.
5. Overall, the ASP demonstrated robustness to address the needs identified in the Valley South System service territory. The project design offers several advantages that can also overcome the variability and uncertainty associated with the load forecast. The available flexibility through system tie-lines provides relief to system operations under N-1, N-2, and HILP events that affect the region.

5 SCREENING AND RELIABILITY ASSESSMENT OF ALTERNATIVES

5.1 Introduction

The objective of this analysis is to identify and screen potential alternatives that meet the project objectives detailed in Section 1.2. Each of these alternatives is evaluated using the criteria established in Section 3.2.4.

The considered alternatives are evaluated for their capability to address system capacity and reliability needs. The alternatives are categorized as Minimal Investment Alternatives, Conventional, Non-Wire Alternatives (NWA), and Hybrid solutions.

Minimal Investment Alternatives can also be referred to as a "do nothing" scenario in which no large project is implemented to address the needs of the system. These include spare equipment investments, re-rating or equipment upgrades, component hardening, vegetation management, undergrounding T&D, reinforcement of poles and towers, and emergency operations like load shedding relays. Conventional solutions include alternative substation or transmission line configurations. NWAs include energy storage, demand response, energy efficiency programs, DERs, and other smart grid investments like smart meters. Hybrid solutions are a combination of Conventional and NWAs.

The solution alternatives are organized into four primary categories, as outlined in Figure 5-1.

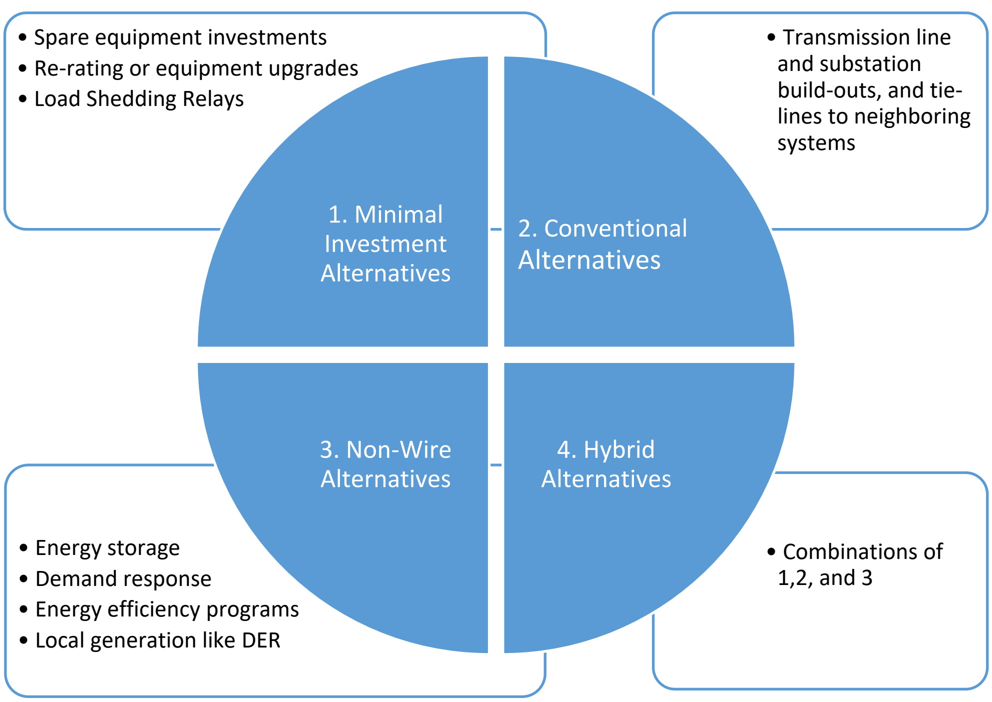


Figure 5-1. Categorization of Considered Alternatives

The highlights of the procedure used to identify potential alternative projects are as follows:

- Use reliability analysis results with no project in service and available reports detailing the layout of the Valley South System to establish Minimum Investment Alternatives to mitigate and meet the objectives.
- An exhaustive search (brute force) approach was used to establish system tie-lines between the Valley South System and neighboring systems. Tie-lines performance was evaluated under the most constraining conditions identified from the "no project" scenario results. Figure 5-2 describes the Valley South System relative to neighboring electrical systems.
- Seek guidance from the LAR metrics to provide the viability of alternatives. For example, the identified MWh need is large and predominantly occurs during off-peak hours of the day when PV-DER type solutions might not be available.

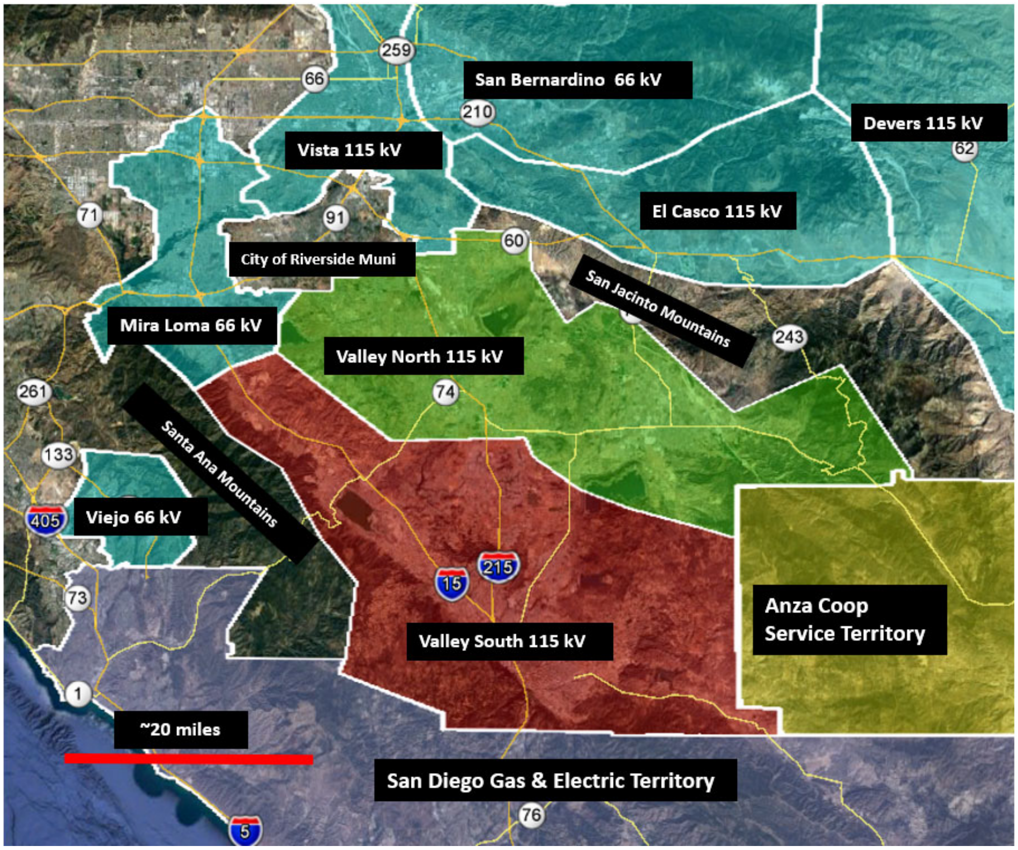


Figure 5-2. Valley System and Neighboring Electrical Systems

5.2 Project Screening and Selection

The initial screening process resulted in a total of 17 alternatives. These included all categories of options outlined in Figure 5-1. The 17 alternatives were preliminarily screened through a fatal flaw analysis driven by the overall project objectives. Through this process, four alternatives were dropped from further consideration. The dropped alternatives included 1) utilization of spare transformer for the Valley South System, 2) upgrading transformer ratings, 3) investing in load shedding relays, and 4) installation of two additional 500/115kV transformer banks. Upon further inspection and analysis, these four alternatives were determined to not satisfy all project objective needs or were not feasible from an implementation or constructability perspective.

The final list of 13 alternatives included a combination of conventional, non-wire, and hybrid solutions. These alternatives are presented below. Further details pertaining to the scope, design, and project performance are described in the upcoming sections. Note that the ASP and project alternatives are identified using an alphabetic character, A through M, which is used throughout this report to refer to each alternative.

Conventional Alternatives

The considered conventional transmission alternatives are detailed below.

A. Alberhill System Project
B. San Diego Gas & Electric Project
C. SCE Orange County Project
D. Menifee Project
E. Mira Loma Project
F. Valley South to Valley North Project
G. Valley South to Valley North to Vista Project

Non-Wire Alternatives

The following non-wire alternatives have been considered:

H. Centralized BESS in Valley South Project

Hybrid Solutions

The following hybrid solutions that involve a combination of conventional and hybrid solutions have been considered in this analysis:

I. Valley South to Valley North and Distributed BESS in Valley South Project
J. San Diego Gas & Electric and Centralized BESS in Valley South (Alternatives B + H)
K. Mira Loma and Centralized BESS in Valley South (Alternatives E + H)
L. Valley South to Valley North and Centralized BESS in Valley South and Valley North (Alternatives F + H)
M. Valley South to Valley North to Vista and Centralized BESS in Valley South (Alternatives G + H)

5.3 Detailed Project Analysis

In the detailed project analysis, the reliability assessment framework was applied to all 13 considered alternatives. The performance and benefits of each alternative were computed in comparison to the baseline scenario (i.e., no project in service) following the methodology detailed in Section 3.2. The results of the baseline scenario are presented in Section 4.2 and the ASP (Alternative A) in Section 4.3. The performance of each alternative is presented for the range of load forecast sensitivities (PVWatts, Effective PV, and Spatial Base).

5.3.1 San Diego Gas & Electric (Project B)

The original premise for this project is to construct a new 230/115 kV substation that provides power via the San Diego Gas & Electric system and to transfer some of SCE's distribution substations to this new 230/115 kV system. This project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.1.1 Description of Project Solution

The proposed project would transfer SCE's Pechanga and Pauba 115/12 kV distribution substations to a new 230/115 kV transmission substation provided service from the SDG&E electric system. The proposed project would include the following components:

1. The point of interconnection would be a new 230/115 kV substation between the SCE-owned Pechanga Substation and SDG&E-owned Talega-Escondido 230 kV transmission line to the south. Two 230/115 kV transformers (one load-serving and one spare).
2. New double-circuit 230 kV transmission line looping the new substation into SDG&E's Talega-Escondido 230 kV transmission line.
3. New 115 kV line construction to allow the transfer of Pechanga and Pauba Substations from Valley South to new 230/115 kV substation.
4. Create system tie-lines between the new 230/115 kV system and the Valley South System through normally-open circuit breakers at SCE's Triton and Moraga Substations to provide operational flexibility and to accommodate potential future additional load transfers.
5. Rebuild of existing Pechanga Substation and/or expansion of existing property at Pechanga Substation to accommodate required new 115 kV switch rack positions.

Figure 5-3 presents a high-level representation of the proposed configuration.

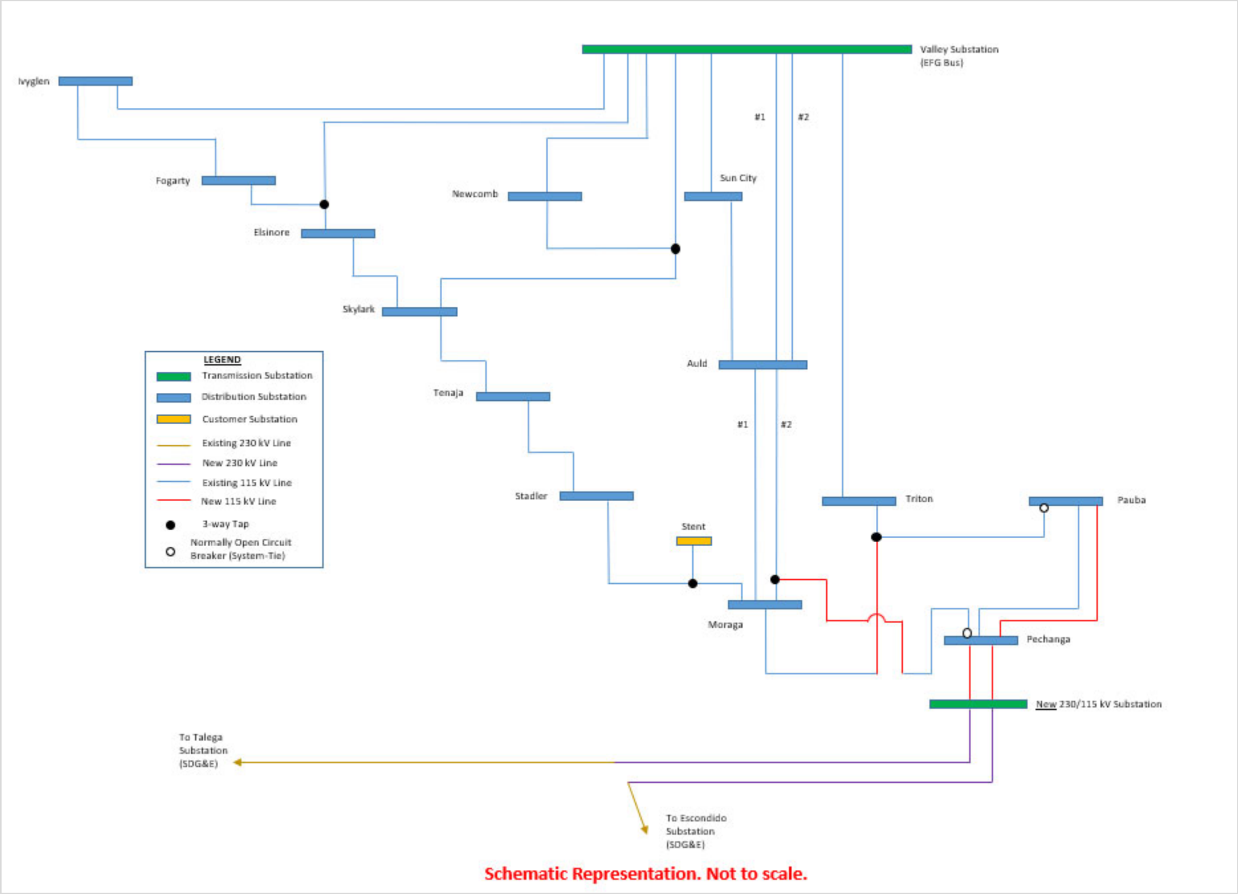


Figure 5-3. SDG&E Project Scope

5.3.1.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-1 for the Effective PV Forecast, Table 5-2 for the Spatial Base Forecast, and Table 5-3 for the PVWatts Forecast.

Table 5-1. SDG&E N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	48,529
2038	0	0	0	50,505
2043	82	31	4	52,481
2048	244	63	7	54,457

Table 5-2. SDG&E N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	44,182
2022	0	0	0	44,715
2028	0	0	0	46,963
2033	0	0	0	48,837
2038	199	56	6	50,710
2043	655	112	12	52,584
2048	1,499	152	28	54,457

Table 5-3. SDG&E N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	45,310
2038	0	0	0	46,470
2043	0	0	0	47,630
2048	3	3	1	48,791

5.3.1.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-4 for the Effective PV Forecast, Table 5-5 for the Spatial Base Forecast, and Table 5-6 for the PVWatts Forecast.

Table 5-4. SDG&E N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	20,830	15,152	428 ~~431~~
2028	0	0	0	52,762	17,895	636~~639~~
2033	0	0	0	79,372	21,123	926~~932~~
2038	0	0	0	105,982	24,949	1,274~~1,282~~
2043	0	0	0	132,591	28,757	1,662~~1,672~~
2048	0	0	0	159,201	31,740	1,978 ~~1,990~~

Table 5-5. SDG&E N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	20,830	15,677	468
2022	0	0	0	30,189~~40,890~~	16,727	545
2028	0	0	0	86,343~~161,248~~	21,517	958
2033	0	0	0	133,137~~261,546~~	26,018	1,380
2038	0	0	0	179,931~~361,845~~	31,008	1,889
2043	30	7	4	226,725~~462,143~~	35,874	2,413
2048	196	18	8	273,520~~562,442~~	40,207	2,937

Table 5-6. SDG&E N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	20,830	15,152	428
2028	0	0	0	36,859	17,895	636
2033	0	0	0	50,217	17,971~~17,467~~	641~~605~~
2038	0	0	0	63,575	20,763	896
2043	0	0	0	76,933	23,589	1,146
2048	0	0	0	90,291	25,756	1,352

In analyzing the SDG&E project, the following constraints (Table 5-7) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-7, only thermal violations associated with each constraint are reported.

Table 5-7. List of SDG&E Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2034	2040	2048
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore	N-1	Valley EFG - Newcomb-Skylark	2043	-	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22	N-1	Valley EFG - Elsinore-Fogarty	2043	-	-
Valley EFG-Tap 22	N-1	Valley EFG - Newcomb	2043	-	-

5.3.1.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the SDG&E Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between baseline and SDG&E for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 5-8 for the three forecasts.

Table 5-8. Cumulative Benefits – San Diego Gas & Electric

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	200,879	214,200	249,117
N-1	LAR (MWh)	6,375	21,684	7~~2,688~~5,545
N-1	IP (MW)	467	780	1,321
N-1	PFD (hr)	1,320	1,999	3,432
N-1	Flex-1 (MWh)	3,362,638	5,~~411~~414,~~173~~801	9,902,236~~19,116,843~~
N-1	Flex-2-1 (MWh)	3,167,267	3,217,646	3,402,545
N-1	Flex-2-2 (MWh)	65,442	76,~~509~~689	97,230
N-0	LAR (MWh)	22,748	55,563	132,227
N-0	IP (MW)	2,710	3,726	4,978
N-0	PFD (hr)	410	775	1,444

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SDG&E Project. In particular, the range of benefits is substantial in the N-1 category. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. The project also provides overall loss reduction primarily because it displaces loads at the southern border of the Valley South System service territory, thereby reducing the need for power to travel a longer distance from the source to delivery. Also, the flexibility benefits offered by the solution are limited in comparison to the ASP.

5.3.1.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided only in the near- and mid-term horizon. This trend is observable across all forecast sensitivities. Under N-0, 240 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 1,500 MWh under the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 132.2 GWh of avoided LAR.
2. With the SDG&E Project in service, the N-1 benefits in the system range from 6.3 to 72.6 GWh through all forecasts. The design of the SDG&E Project displaces two relatively large load centers located at the southern border of the Valley South System. By the nature of radial networks, all flows were originally moving in the direction of these loads. With load transfer and circuit reconfiguration, significant benefits are gained under N-1 outage conditions in the Valley South System. In the Spatial Base Forecast, by the year 2043, overloads due to N-1 events are observed in the system.
3. The project provides considerable flexibility to address planned, unplanned, or emergency outages in the system while also providing benefits to address needs under the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.
4. Following a HILP event, the SDG&E Project can recover approximately 280 MW of load from the Valley South System, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, SDG&E did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in the near-term horizon and under the lower range of forecast sensitivities.

5.3.2 SCE Orange County (Project C)

The SCE Orange County Project was evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.2.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection is a new substation with 220/115 kV transformation, southwest of SCE's Tenaja and Stadler Substations in the Valley South System.

2. Looping the San Onofre–Viejo 220 kV line to the new 220/115 kV substation. This configuration would include the construction of the new 230 kV double-circuit transmission line.
3. The proposed solution would transfer SCE's Tenaja and Stadler 115/12 kV Substations to the new 220/115 kV system through the construction of new 115 kV lines.
4. Normally-open circuit breakers at Skylark and Stadler Substations would create system tie-lines providing operational flexibility to accommodate future load transfers.

Figure 5-4 presents a high-level representation of the proposed configuration.

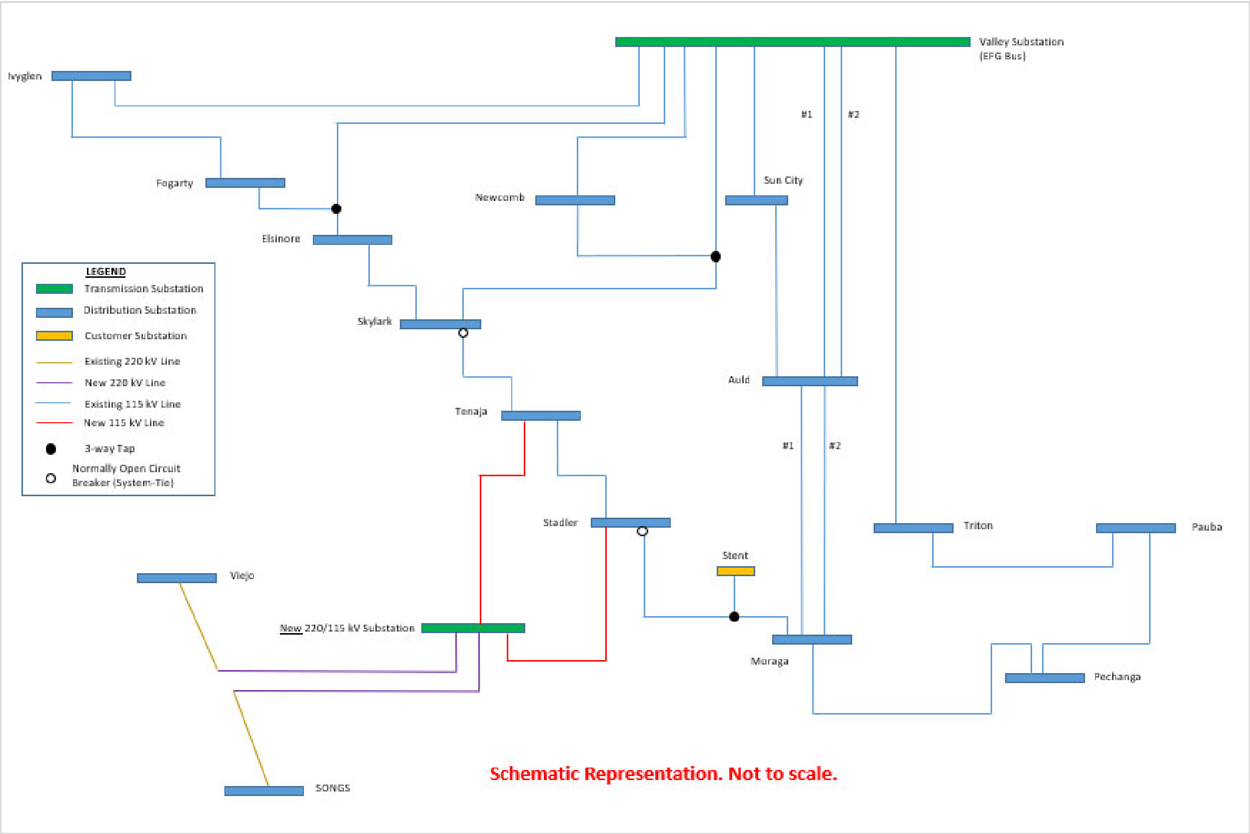


Figure 5-4. SCE Orange County Project Scope

5.3.2.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-9 for the Effective PV Forecast, Table 5-10 for the Spatial Base Forecast, and Table 5-11 for the PVWatts Forecast.

Table 5-9. SCE Orange County N-0 System Performance (Effective PV Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	**2022**	0	0	0	43,189
	2028	0	0	0	45,593
	2033	0	0	0	47,596
	2038	0	0	0	49,599
	2043	72	31	4	51,602
	2048	232	65	7	53,605

Table 5-10. SCE Orange County N-0 System Performance (Spatial Base Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	**2021**	0	0	0	43,574
	2022	0	0	0	44,330
	2028	0	0	0	41,444
	2033	0	0	0	45,672
	2038	183	55	5	49,899
	2043	536	111	11	54,126
	2048	1,426	159	27	58,353

Table 5-11. SCE Orange County N-0 System Performance (PVWatts Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	**2022**	0	0	0	43,189
	2028	0	0	0	45,593
	2033	0	0	0	45,187
	2038	0	0	0	46,843
	2043	0	0	0	48,500
	2048	0	0	0	50,156

5.3.2.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-12 for the Effective PV Forecast, Table 5-13 for the Spatial Base Forecast, and Table 5-14 for the PVWatts Forecast.

Table 5-12. SCE Orange County N-1 System Performance (Effective PV Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2022**	0	0	0	55,886	14,219	344 ~~347~~
	2028	13	3	5	142,815 ~~156,480~~	16,791	519~~522~~
	2033	35	3	2	215,046 ~~240,308~~	19,823	769 ~~774~~
	2038	130	14	7	288,277 ~~324,136~~	23,407	1,078 ~~1,085~~
	2043	313	26	14	359,507 ~~407,965~~	27,650	1,413~~1,483~~
	2048	578	36	28	417,292 ~~491,793~~	29,833	1,703~~1,714~~

Table 5-13. SCE Orange County N-1 System Performance (Spatial Base Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2021**	5	3	2	55,886	14,711	375
	2022	10	3	2	77,708.23 ~~99,498~~	15,692	438
	2028	38	5	4	208,643.16 ~~361,174~~	20,192	798
	2033	176	17	8	317,755.59 ~~579,237~~	24,412	1,169
	2038	497	32	24	426,868.03 ~~797,300~~	29,138	1,633
	2043	1,179	46	37	535,980.47 ~~1,015,363~~	33,790	2,108
	2048	2,275	74	56	645,092.91	37,969	2,570

					~~1,233,426~~		

Table 5-14. SCE Orange County N-1 System Performance (PVWatts Forecast)

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2022**	0	0	0	55,886~~63,777~~	14,219	344
	2028	13	3	5	103,236	16,791	519
	2033	15	3	6	142,695	16,863	523
	2038	32	3	10	182,154	19,485	735
	2043	95	10	21	221,613	22,133	968
	2048	159	16	23	261,072	24,165	1,146

In analyzing the SCE Orange County Project, the following constraints (Table 5-15) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-15, only thermal violations associated with each constraint are reported.

Table 5-15. List of SCE Orange County Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2034	2040	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2043	-	-
Auld-Moraga #1	N-1	Auld-Moraga #2	2033	2038	2048
Valley EFG-Triton	N-1	Moraga-Pechanga	2043	-	-
Valley EFG-Sun City	N-1	Valley EFG -Auld #1	2043	-	-
Valley EFG-Auld #1	N-1	Valley EFG -Sun City	2048	-	-
Valley EFG-Auld #1	N-1	Valley EFG -Auld #2	2043	-	-
Valley EFG-Sun City	N-1	Valley EFG -Auld #2	2043	-	-
Auld-Moraga #1	N-1	Valley EFG - Triton	2043	2048	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.2.4 Evaluation of Benefits

The established performance metrics were compared between baseline and SCE Orange County Project to quantify the overall benefits accrued over a 30-year study. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The cumulative value of the benefits over the 30-year horizon is presented in Table 5-16 for the three forecasts.

Table 5-16. Cumulative Benefits – SCE Orange County

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	193,424	187,601	203,637
N-1	LAR (MWh)	5,159~~64~~	17,520	59,898~~57,040~~
N-1	IP (MW)	337	447	661
N-1	PFD (hr)	1,055	1,785	2,923
N-1	Flex-1 (MWh)	583,840	1,278,674~~447,937~~	4,209,439~~9,232,289~~
N-1	Flex-2-1 (MWh)	3,200,515	3,255,754	3,449,007
N-1	Flex-2-2 (MWh)	69,270	81,~~316~~467	103,655
N-0	LAR (MWh)	22,751	55,560	133,064
N-0	IP (MW)	2,713	3,724	4,986
N-0	PFD (hr)	411	776	1,456

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SCE Orange County Project. In particular, the range of benefits is substantial in the N-1 category and loss reduction. The project's contribution to loss reduction is primarily because it displaces loads at the southern border of the Valley South System service territory, thereby reducing the need for power to travel a longer distance from the source to point of delivery. Additionally, this project displaces loading on subtransmission lines with a significant contribution to overall system losses (namely, Tap 22–Skylark and Skylark–Tenaja) in the Valley South System. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. Also, the flexibility benefits offered by the solution are limited in comparison to the ASP.

5.3.2.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformer is avoided only in the near- and mid-term horizon. Under N-0, 230 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 1,400 MWh under Spatial Base Forecast for 2048. Across all sensitivities, the benefits range from 22.7 to 133 GWh of avoided LAR.
2. Considerable reduction in N-1 overloads is observed in the near-term and long-term horizons for all forecasts. With SCE Orange County Project in service, the N-1 LAR benefits in the system range from 5.1 to 57 GWh through all forecasts.
3. The project provides reasonable flexibility to address planned, unplanned, or emergency outages in the system while also providing benefits to address needs under the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.

4. Under peak loading conditions, the SCE Orange County Project would be able to approximately serve 280 MW of load from Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, the SCE Orange County project did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in the near- or mid-term horizon and under the lower range of forecast sensitivities.

5.3.3 Menifee (Project D)

The Menifee Project would construct a new substation located approximately 0.5 miles west of Valley Substation. The scope would include 500/115 kV transformation and associated 500 and 115 kV switch racks. Power would be supplied by looping in SCE's existing Serrano–Valley 500 kV line. SCE's existing Newcomb and Sun City distribution substations would be transferred to this new system providing relief on the Valley South System transformers. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.3.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection would be a new substation with two 500/115 kV transformers (including the spare) and associated facilities located approximately 0.5 miles west of Valley Substation. It would be provided power by looping in SCE's existing Serrano–Valley 500 kV line.
2. The proposed solution would transfer the loads at Newcomb and Sun City Substations in the Valley South System.
3. The 115 kV lines currently serving Newcomb and Sun City substations would be transferred to the new system involving a combination of new 115 kV lines and circuit reconfiguration.
4. Creates two system ties between the new system and the Valley South System through an open circuit breaker at Sun City and Valley Substations to provide operational flexibility.
5. Reconductor existing Auld–Sun City 115 kV line which would become the Valley–Auld–Sun City 115 kV line.
6. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-5 presents a high-level representation of the proposed configuration.

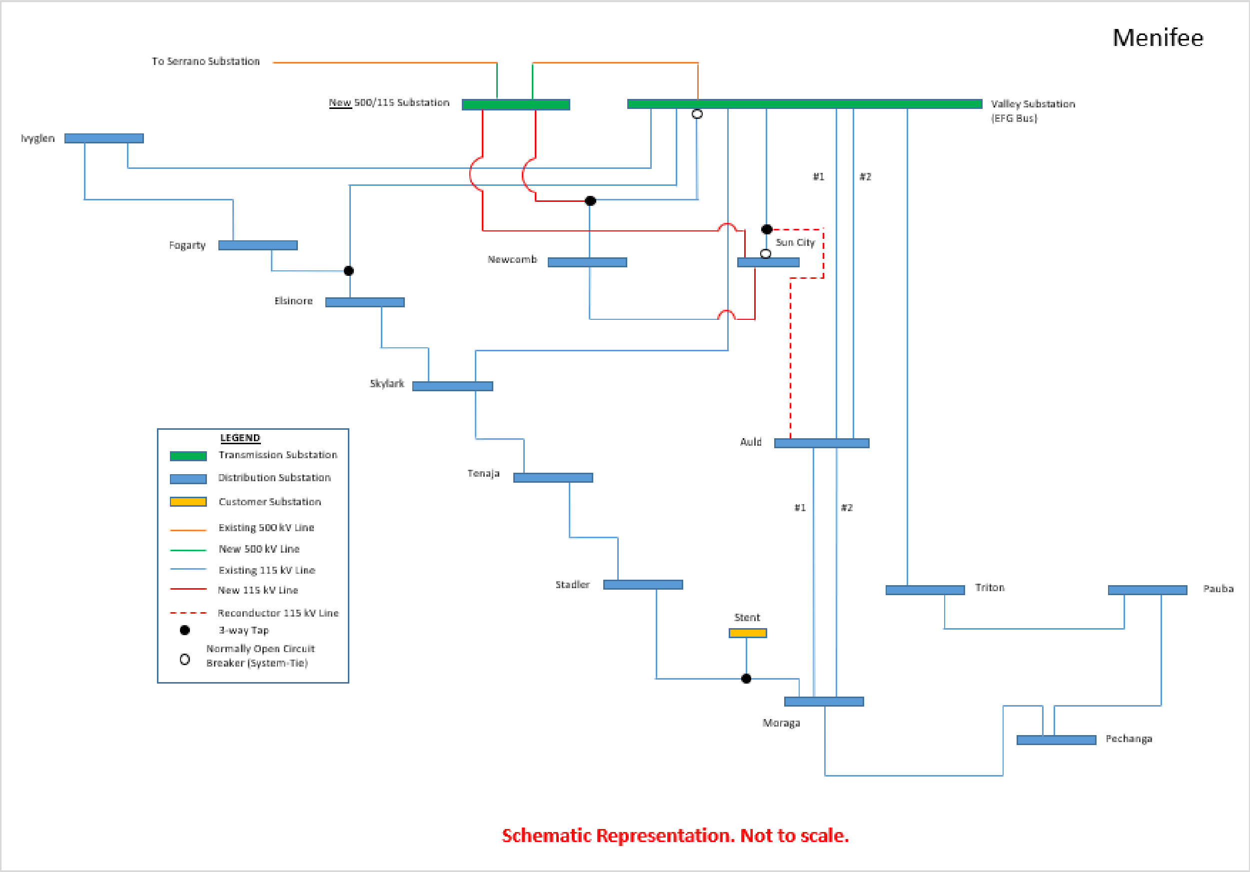


Figure 5-5. Menifee Project Scope

5.3.3.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-17 for the Effective PV Forecast, Table 5-18 for the Spatial Base Forecast, and Table 5-19 for the PVWatts Forecast.

Table 5-17. Menifee N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,898
2028	0	0	0	51,308
2033	0	0	0	53,316
2038	0	0	0	55,324
2043	3	3	1	57,332
2048	114	39	4	59,341

Table 5-18. Menifee N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,287
2022	0	0	0	50,035
2028	0	0	0	53,305
2033	0	0	0	56,030
2038	73	29	4	58,754
2043	385	83	8	61,479
2048	902	130	14	64,204

Table 5-19. Menifee N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,898
2028	0	0	0	51,308
2033	0	0	0	50,553
2038	0	0	0	52,316
2043	0	0	0	54,079
2048	0	0	0	55,855

5.3.3.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-20 for the Effective PV Forecast, Table 5-21 for the Spatial Base Forecast, and Table 5-22 for the PVWatts Forecast.

Table 5-20. SCE Menifee N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	24,267~~40,625~~	571~~574~~
2028	0	0	0	54,051	28,475 ~~46,206~~	842~~848~~
2033	4	2	2	81,311	33,145 ~~52,058~~	1,161~~1,168~~
2038	103	14	19	108,570	38,226 ~~58,178~~	1,586~~1,596~~
2043	472	22	67	135,830	42,887 ~~63,655~~	2,025~~2,038~~
2048	1040	38	155	163,090	46,332 ~~67,659~~	2,369~~2,384~~

Table 5-21. Menifee N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	25,088	616
2022	0	0	0	~~54,465~~31,297	26,706	715
2028	4	2	2	~~253,225~~91,039	33,690	1,202
2033	156	18	22	~~418,858~~140,824	39,569	1,710
2038	722	37	70	~~584,491~~190,610	45,496	2,286
2043	1,968	56	163	~~750,124~~240,395	50,845	2,902
2048	3,737	68	272	~~915,757~~290,181	55,391	3,458

Table 5-22. Menifee N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	24,267	571
2028	0	0	0	46,835	28,475	843
2033	0	0	0	68,082	28,590	850

2038	0.4	0.4	1	89,330	32,641	1,122
2043	47	10	11	110,577	36,471	1,426
2048	138	17	22	131,824	39,242	1,679

In analyzing the Menifee project, the following constraints (Table 5-23) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-23, only thermal violations associated with each constraint are reported.

Table 5-23. List of Menifee Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.3.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Menifee Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-24 for the three forecasts.

Table 5-24. Cumulative Benefits – Menifee

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	41,268	33,102	41,920
N-1	LAR (MWh)	5,724	15,368	~~47,913~~51,103
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,370
N-1	Flex-1 (MWh)	2,795,076	5,35~~1,804~~6,744	~~14,163,311~~9,661,860
N-1	Flex-2-1 (MWh)	2,860,352	2,~~368,156~~885,882	3,029,498
N-1	Flex-2-2 (MWh)	59,402	69,~~175~~398	87,588
N-0	LAR (MWh)	22,751	56,229	136,040
N-0	IP (MW)	2,713	3,930	5,371
N-0	PFD (hr)	411	800	1,519

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Menifee Project. By design, the project includes a permanent transfer of relatively large load centers in the Valley South System during the initial years. This provides significant N-0 system relief, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers.

5.3.3.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided only in the near-term horizon. Under N-0, 114 MWh of LAR is recorded in the Effective PV Forecast for 2048, and 985 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 135.6 GWh of avoided LAR.
2. N-1 overloads are observable in the mid-term and long-term horizons for all forecasts. With the project in service, the N-1 LAR benefits in the system range from 5.7 to 48 GWh through all forecast sensitivities.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South system.
4. Following a HILP event, the Menifee Project can serve a total of approximately 160 MW of load in Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, Menifee did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.4 Mira Loma (Project E)

The objective of this alternative is to take advantage of the Mira Loma system to provide a new source of supply into the Valley South service area. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.4.1 Description of Project Solution

1. Construct a new 220/115 kV substation with two transformers (including a spare) and associated facilities. The substation would be located near SCE's existing Mira Loma Substation and would be provided power by looping in an existing 220 kV line. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
2. Transfer load at Ivyglen and Fogarty Substations from the Valley South System to the new 220/115 kV system created.
3. Creates two system tie-lines between Valley South and the new system at Valley Substation and Fogarty Substation, respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-6 presents a high-level representation of the proposed configuration.

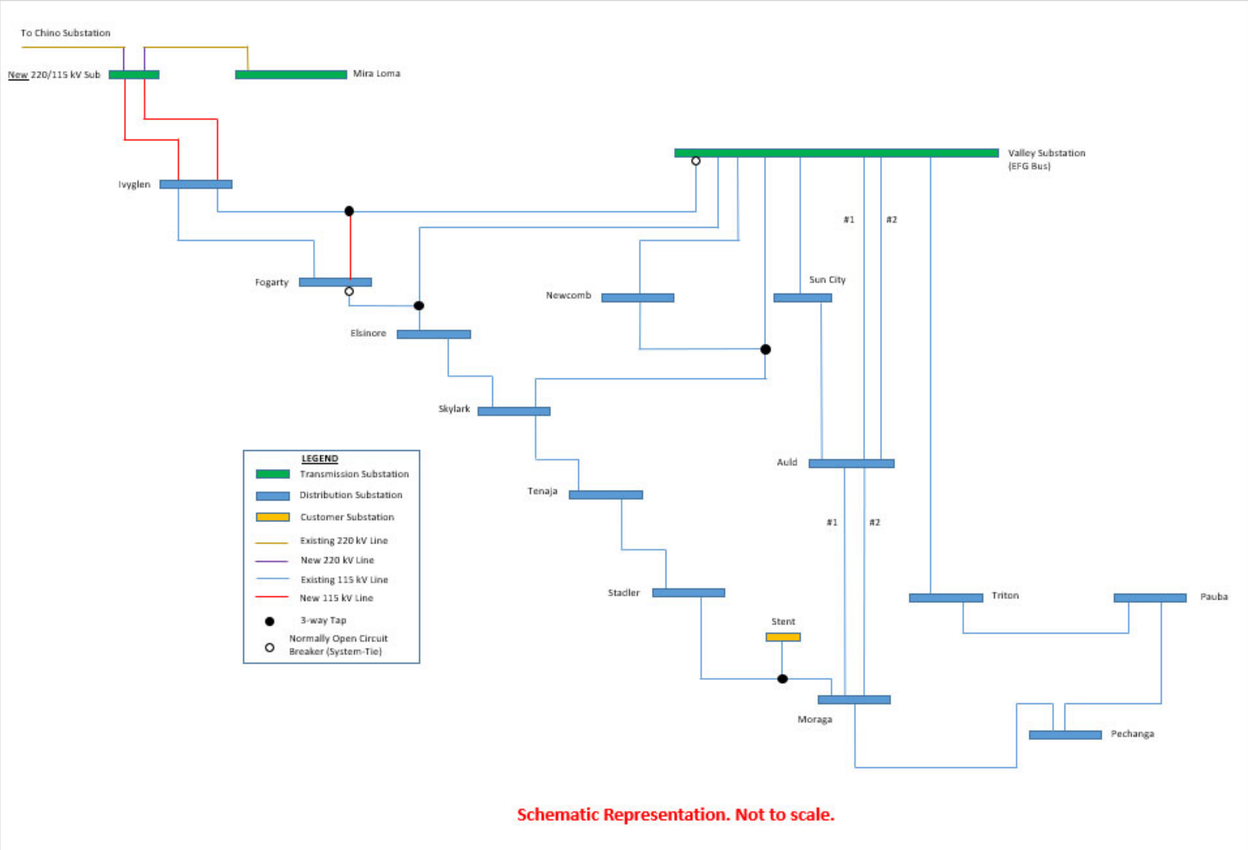


Figure 5-6. Tie-line to Mira Loma Project Scope

5.3.4.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-25 for the Effective PV Forecast, Table 5-26 for the Spatial Base Forecast, and Table 5-27 for the PVWatts Forecast.

Table 5-25. Mira Loma N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	82	31	4	53,021
2038	314	84	9	55,097
2043	807	138	22	57,173
2048	1,905	184	30	59,250

Table 5-26. Mira Loma N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,849
2022	0	0	0	49,618
2028	106	38	4	42,629
2033	607	104	12	48,041
2038	1,449	172	29	53,453
2043	3,365	238	45	58,864
2048	4,958	294	81	64,276

Table 5-27. Mira Loma N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	0	0	0	53,021
2038	58	24	4	55,097
2043	273	69	7	57,173
2048	526	184	30	59,250

5.3.4.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-28 for the Effective PV Forecast, Table 5-29 for the Spatial Base Forecast, and Table 5-30 for the PVWatts Forecast.

Table 5-28. Mira Loma N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	39,336	82,321	650~~4~~
2028	0	0	0	99,638	87,598	944~~9~~
2033	18	4	7	149,889	93,115	1,299~~306~~
2038	94	15	27	200,140	98,884	1,~~777~~766
2043	493	30	66	250,391	104,047	2,~~232~~219
2048	1,151	40	127	300,643	107,821	2,~~624~~609

Table 5-29. Mira Loma N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	39,336	83,384	708
2022	0	0	0	~~91~~56,~~765~~324	85,427	828
2028	12	4	7	158,254~~406,336~~	93,744	1,345
2033	253	19	39	243,197~~668,479~~	100,380	1,885
2038	822	36	114	328,139~~930,622~~	106,913	2,513
2043	2427	57	246	413,081~~1,192,765~~	112,783	3,150
2048	4599	77	442	498,023~~1,454,907~~	117,771	3,772

Table 5-30. Mira Loma N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	39,336	82,321	650
2028	0	0	0	93,650	87,598	944
2033	0	0	0	138,912	87,737	951
2038	4	2	4	184,174	92,531	1,259
2043	64	9	16	229,436	96,915	1,601
2048	~~203~~197	20	29	274,697	100,017	1,852

In analyzing the Mira Loma Project, the following constraints (Table 5-31) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-31, only thermal violations associated with each constraint are reported.

Table 5-31. List of Mira Loma Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2026	2031	2036
Valley EFG-Sun City	N-0	N/A (base case)	2044	-	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2044	-	-
Tap 39-Elsinore #1	N-0	N/A (base case)	2044	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2032	2038	2048
Valley EFG-Tap 39 #1	N-1	Valley EFG-Newcomb-Skylark	2032	2038	2043
Tap 39-Elsinore #1	N-1	Valley EFG-Newcomb-Skylark	2032	2038	2043
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2028	2033	2038
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2038	2043	-
Valley EFG-Sun City	N-1	Valley EFG-Auld #1	2038	2043	-
Valley EFG-Auld #1	N-1	Valley EFG-Sun City	2038	2045	-
Valley EFG-Tap 22#1	N-1	Valley EFG-Newcomb	2038	2043	-
Valley EFG-Auld #1	N-1	Valley EFG-Auld #2	2038	2043	-
Valley EFG-Sun City	N-1	Valley EFG-Auld #2	2038	2043	-
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2033	2038

5.3.4.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Mira Loma Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and Mira Loma for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-32 for all three forecasts.

Table 5-32. Cumulative Benefits – Mira Loma

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	48,851	40,333	47,004
N-1	LAR (MWh)	~~2,548~~5,454	15,237	4~~2,681~~5,012
N-1	IP (MW)	~~42~~355	421	603
N-1	PFD (hr)	1,~~011~~041	1,125	214
N-1	Flex-1 (MWh)	623,316	3,25~~1,880~~5,037	6,~~363,238~~500,106
N-1	Flex-2-1 (MWh)	1,252,410	1,263,410	1,326,687
N-1	Flex-2-2 (MWh)	55,850	~~64~~65,~~919~~168	82,069
N-0	LAR (MWh)	~~18,924~~19,577	~~50~~44,~~134~~963	~~110,252~~98,703
N-0	IP (MW)	1,720	2,270	2,721
N-0	PFD (hr)	362	554	935

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Mira Loma Project. Although the project demonstrates N-0 benefits in the short-term horizon, the project does not completely address the N-0 overload condition on the Valley South System transformers. In the Spatial Base Forecast, the project fails to satisfy needs in the short-term horizon as well, resulting in 106 MWh of LAR by 2028. The availability of system tie-lines does provide incremental flexibility to support emergency and maintenance conditions in the system. However, these benefits are limited in comparison to other solutions like ASP.

5.3.4.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, limited relief is available to overload conditions on the Valley South System transformers. Under N-0, 1,905 MWh of LAR is recorded under the Effective PV Forecast for 2048. Similarly, the LAR of 5,000 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range from 18.9 to 110 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 2.5 to 42.6 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South system.
4. Following a HILP event, Mira Loma can recover approximately 110 MW of load in Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, Mira Loma did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.5 Valley South to Valley North project (Project F)

The objective of this project is to transfer Newcomb and Sun City Substations from the Valley South system to the Valley North System. Under normal conditions, the Valley North System does not approach its transformer rated capacity until 2045 in the Spatial Base Forecast. In all other forecasts, the loading does not exceed transformer capacity. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North system have not been considered in the metrics.

The project was considered to leverage the capabilities of tie-lines to move loads between the Valley South System and the Valley North System. However, this transfer would not satisfy the short-term and long-term objectives of the projects. No incremental benefits are provided to the Valley South System in this configuration because no additional load can be transferred to Valley North during emergency or maintenance conditions in the network. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.5.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through the construction of new 115 kV lines.
2. Normally-open circuit breakers at the Valley South bus and Sun City Substation are maintained as system tie-lines between Valley North and Valley South for transfer flexibility.
3. Reconductor existing Auld–Sun City 115 kV line which would become the Valley–Auld–Sun City 115 kV line.
4. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-7 presents a high-level representation of the proposed configuration.

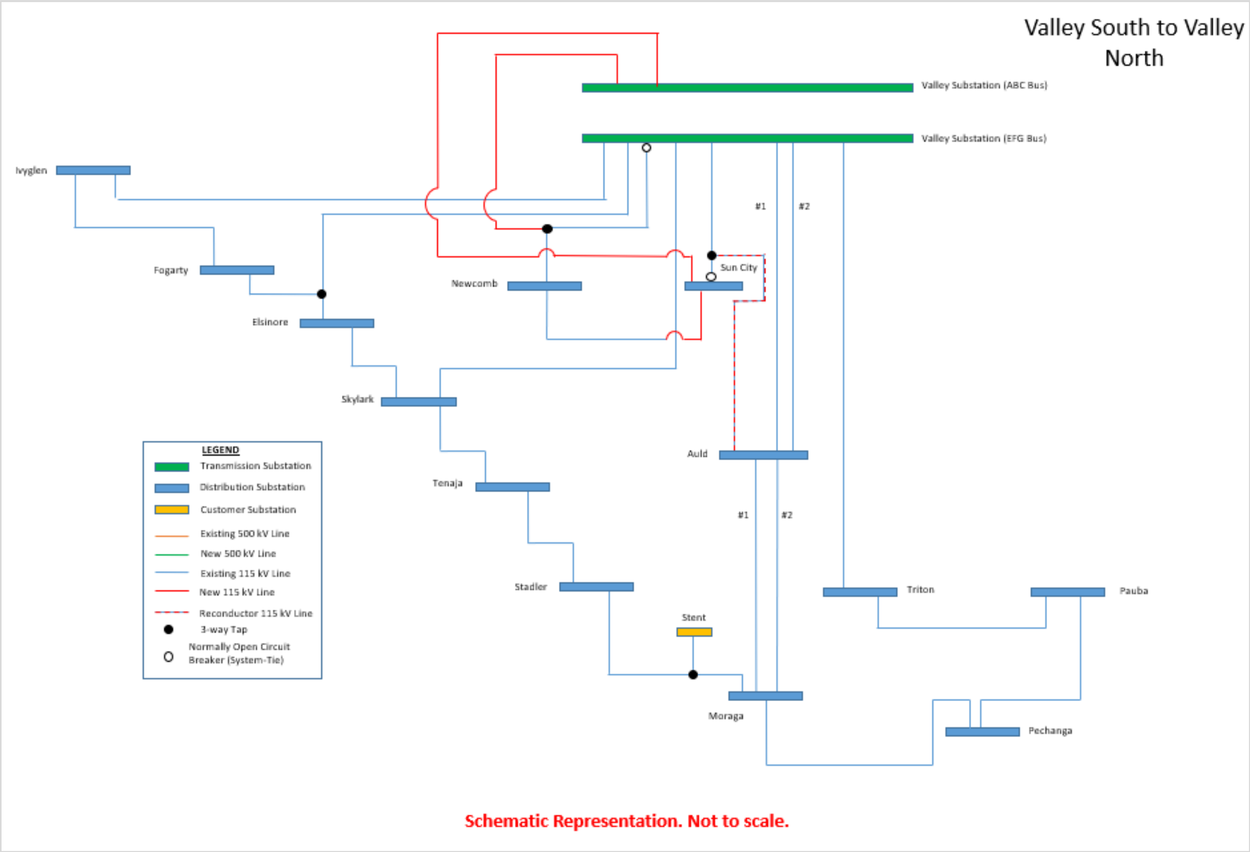


Figure 5-7. Tie-lines between Valley South and Valley North Project Scope

5.3.5.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-33 for the Effective PV Forecast, Table 5-34 for the Spatial Base Forecast, and Table 5-35 for the PVWatts Forecast.

Table 5-33. Valley South to Valley North N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	136	14	4	55,858
2043	779	44	20	57,898
2048	2,680	192	55	59,939

Table 5-34. Valley South to Valley North N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	305	56	13	56,568
2038	2,468	173	56	59,336
2043	8,146	310	104	62,104
2048	16,818	433	165	64,872

Table 5-35. Valley South to Valley North N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	94	49	6	54,713
2048	750	202	19	56,399

5.3.5.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-36 for the Effective PV Forecast, Table 5-37 for the Spatial Base Forecast, and Table 5-38 for the PVWatts Forecast.

Table 5-36. Valley South to Valley North N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571~~574~~
2028	0	0	0	54,051	133,688	843~~848~~
2033	4	2	2	81,311	139,702	1,161 ~~1,168~~
2038	103	14	19	108,570	145,991	1,586~~1,596~~
2043	472	27	67	135,830	151,619	2,025~~2,038~~
2048	1040	38	155	163,090	155,733	2,369 ~~2,384~~

Table 5-37. Valley South to Valley North N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	129,095	616
2022	0	0	0	~~54,465~~31,297	140,388	1,202
2028	4	2	2	~~253,225~~91,039	140,388	1,202
2033	156	18	22	~~418,858~~140,824	147,622	1,710
2038	722	37	70	~~584,491~~190,610	154,744	2,286
2043	1968	56	163	~~750,124~~240,395	161,142	2,902
2048	3737	68	272	~~915,757~~290,181	166,580	3,458

Table 5-38. Valley South to Valley North N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	46,835	133,688	843
2033	0	0	0	68,082	133,840	850
2038	0	0	1	89,330	139,065	1,122
2043	47	10	11	110,577	143,845	1,426
2048	138	17	22	131,824	147,226	1,679

In analyzing the Valley North to Valley South Project, the following constraints (Table 5-39) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-39, only thermal violations associated with each constraint are reported.

Table 5-39. List of Valley South to Valley North Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.5.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and the Valley South to Valley North Project for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-40 for the three forecasts.

Table 5-40. Cumulative Benefits – Valley South to Valley North

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,221	26,468
N-1	LAR (MWh)	5,724	15,368	~~47,913~~50,734
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,371
N-1	Flex-1 (MWh)	2,795,076	5,35~~1,804~~6,743	~~14,163,311~~9,661,860
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,~~175~~398	87,588
N-0	LAR (MWh)	20,124	45,492	40,848
N-0	IP (MW)	1,910	3,211	2,380
N-0	PFD (hr)	328	537	288

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North Project. By design, the project includes a permanent transfer of large load centers in the Valley South System during initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. Additionally, the transformer overload condition is propagated to the Valley North System transformers starting from the year 2030 in the Spatial Base Forecast and 2036 in the Effective PV Forecast.

5.3.5.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South transformer is avoided in the near term and long-term horizon till the year 2043. However, the transfer of loads results in overloads on the Valley North transformer by the year 2037. 2,600 MWh of LAR is recorded under N-0 condition in the Effective PV Forecast and 16,800 MWh in the Spatial Base Forecast in the year 2048. Across all sensitivities, the benefits range from 20.1 to 45.4 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 5.7 to 47.9 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. During potential HILP events impacting Valley Substation, the project is unable to serve incremental load in the Valley South system.

5. Overall, the Valley South to Valley North Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.6 Valley South to Valley North to Vista (Project G)

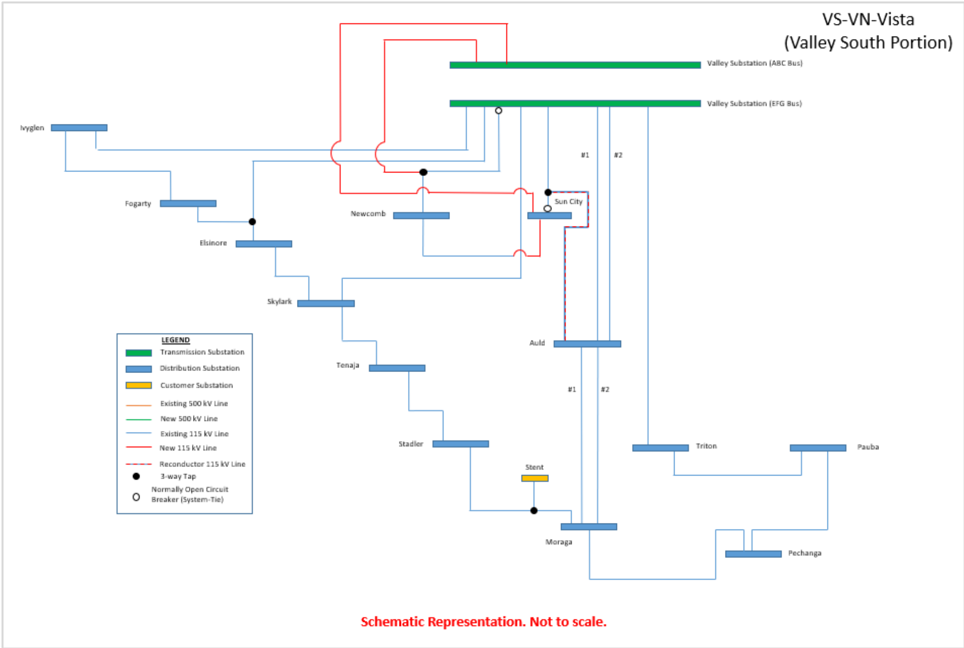
The objective of this project would be to transfer the loads at Newcomb and Sun City Substations to the Valley North System (identical to Project F). Additionally, the load at Moreno Substation in the Valley North System would be transferred to the Vista 220/115 kV system. The premise of this methodology is to relieve loading on the Valley North System to accommodate a load transfer from the Valley South System. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North System, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.6.1 Description of Project Solution

The proposed project would include the following components:

1. Moreno Substation is transferred to Vista 220/115 kV system through existing system tie-lines between Valley North and Vista Systems.
2. New 115 kV line construction to restore subtransmission network connectivity following transfer at Moreno Substation.
3. Normally-open circuit breaker at Moreno Substation to provide a system tie-line between the Vista system and the Valley North System.
4. The proposed project would also transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through the construction of new 115 kV lines (see Project F).
5. Normally-open circuit breakers at the Valley South bus and the Sun City Substation are maintained as system tie-lines between the Valley North System and the Valley South System for transfer flexibility.
6. Reconductor existing Auld–Sun City 115 kV line which would become the Valley–Auld–Sun City 115 kV line.
7. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-8 presents a high-level representation of the proposed configuration.



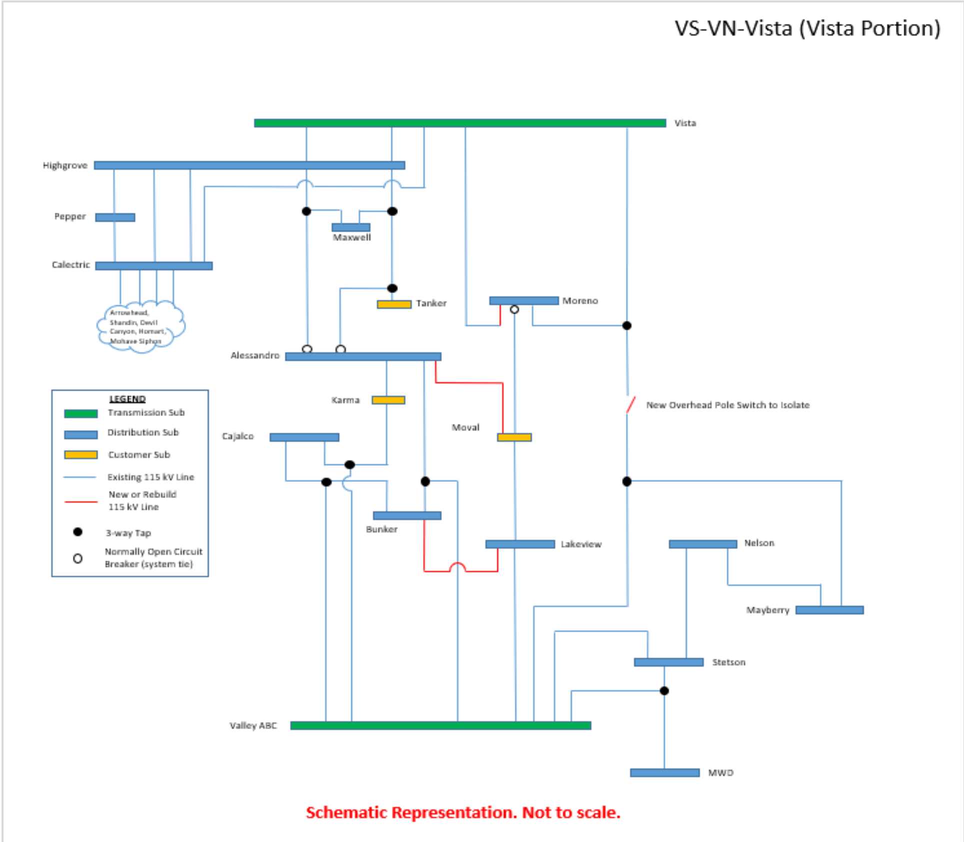


Figure 5-8. Tie-lines between Valley South to Valley North to Vista

5.3.6.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-41 for the Effective PV Forecast, Table 5-42 for the Spatial Base Forecast, and Table 5-43 for the PVWatts Forecast.

Table 5-41. Valley South to Valley North to Vista N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	54,225
2038	0	0	0	55,858
2043	83	31	6	57,898
2048	852	121	22	59,939

Table 5-42. Valley South to Valley North to Vista N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	756	112	23	59,336
2043	3,843	246	66	62,104
2048	9,003	365	119	64,872

Table 5-43. Valley South to Valley North to Vista N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	68	37	5	56,399

5.3.6.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-44 for the Effective PV Forecast, Table 5-45 for the Spatial Base Forecast, and Table 5-46 for the PVWatts Forecast.

Table 5-44. Valley South to Valley North to Vista N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	~~574~~571
2028	0	0	0	54,051	133,688	~~848~~843
2033	4	2	2	81,311	139,702	1,~~168~~161
2038	103	14	19	108,570	145,991	1,~~596~~586
2043	472	27	67	135,830	151,619	2,~~038~~025
2048	1040	38	155	163,090	155,733	2,~~384~~370

Table 5-45. Valley South to Valley North to Vista N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	129,095	616
2022	0	0	0	~~54,465~~31,297	140,388	1,202
2028	4	2	2	~~253,225~~91,039	140,388	1,202
2033	156	18	22	~~418,858~~140,824	147,622	1,710
2038	722	37	70	~~584,491~~190,610	154,744	2,286
2043	1968	56	163	~~750,124~~240,395	161,142	2,902
2048	3737	68	272	290,181~~915,757~~	166,580	3,458

Table 5-46. Valley South to Valley North to Vista N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	46,835	133,688	843
2033	0	0	0	68,082	133,840	850
2038	0	0	1	89,330	139,065	1,122
2043	47	10	11	110,577	143,845	1,426
2048	138	17	22	131,824	147,226	1,679

In analyzing the Valley North to Valley South to Vista Project, the following constraints (Table 5-47) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-47, only thermal violations associated with each constraint are reported.

Table 5-47. List of Valley North to Valley South to Vista Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.6.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North to Vista Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and the Valley South to Valley North to Vista Project for each of the metrics.

The accumulative value of benefits over the 30-year horizon is presented in Table 5-48 for all three forecasts.

Table 5-48. Cumulative Benefits – Valley South to Valley North to Vista

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,221	26,468
N-1	LAR (MWh)	5,724	15,368	~~47,913~~50,735
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,371
N-1	Flex-1 (MWh)	2,795,076	5,~~351~~356,~~804~~743	~~14,163,311~~9,661,860
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,~~175~~398	87,588
N-0	LAR (MWh)	22,613	53,700	91,349
N-0	IP (MW)	2,638	3,569	3,422
N-0	PFD (hr)	399	725	824

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North to Vista Project. By design, the project includes a permanent transfer of large load centers in Valley South during initial years. This provides significant N-0 system relief in Valley South, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. However, the transformer overload condition is propagated to the Valley North System transformers starting from the year 2041 in the Effective PV Forecast. The project also includes a transfer of load from the Valley North System to the Vista System. This temporarily remedies the system overload but does not provide relief over the long-term horizon.

5.3.6.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South system transformers is avoided in the near-term and long-term horizons until the year 2043. However, the transfer of loads results in overloads on the Valley North System transformers in the year 2041, with a transfer of loads to the Vista System. Under N-0, 852 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 9,000 MWh in the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.6 to 91.3 GWh of avoided LAR.
2. N-1 overloads are observable in the mid-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 5.7 to 47.9 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.

4. During potential HILP events affecting Valley Substation, the design of this project does not provide the ability to recover load in the Valley South System through leveraging capabilities of its system tie-lines.
5. Overall, Valley South to Valley North to Vista did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the System

5.3.7 Centralized BESS in Valley South Project (Project H)

The premise of this solution is to utilize BESS to be appropriately sized for meeting the reliability needs of the system. Storage has been separately sized for each of the forecasts under consideration, and their performance has been evaluated. Two locations in the Valley South System are considered, near SCE's existing Pechanga and Auld Substation, respectively, with a maximum capacity to accommodate 200 MW each. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.7.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection would be near Pechanga and/or Auld Substations following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
2. The initial BESS would be constructed near Pechanga Substation with an ultimate design capacity of 200 MW. Once this maximum value is reached, a subsequent and similar installation would be constructed near Auld Substation.
3. In order to meet the future needs of the Valley South System from 2021/2022 to 2048, the following storage sizes have been established. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026). The incremental storage sizes are presented in Table 5-49 through Table 5-51.
4. Due to the radial design of the Valley South System under the study, locating the BESS interconnection near Pechanga or Auld Substations would not result in significant differences to N-0 system performance and reliability indices.
5. In the Valley South system, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-49. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	MW	MWh	MW	MWh
2021	110	433		
2026	64	436		
2031	36	279	28	227
2036			61	485
2041			54	491
2046			18	191
Total Battery Size (including contingency): **371 MW / 2542 MWh**				

Table 5-50. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	MW	MWh	MW	MWh
2022	71	216		
2027	47	281		
2032	57	377		
2037	34	264	18	153
2042			46	375
Total Battery Size (including contingency): **273 MW/ 1666 MWh**				

Table 5-51. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2022	68	216
2027	5	31
2032	46	237
2037	45	286
2042	38	299
Total Battery Size (including contingency): **202 MW/ 1069 MWh**		

Figure 5-9 presents a high-level representation of the proposed configuration. The proposed configuration would loop into or tap along the Pechanga to Pauba circuit and Auld to Moraga circuit.

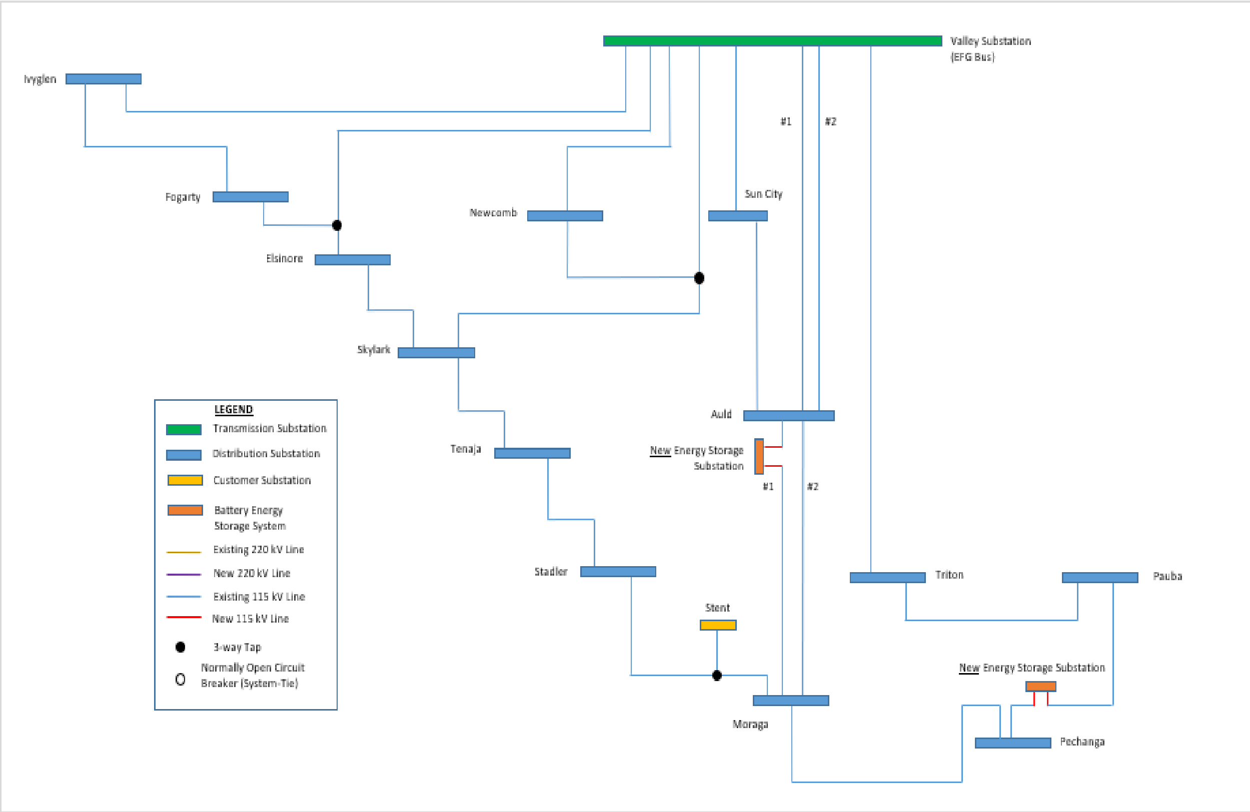


Figure 5-9. Energy Storage at Pechanga and/or Auld Substation as part of the Centralized BESS in the Valley South Project Scope

5.3.7.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-52 for the Effective PV Forecast, Table 5-53 for the Spatial Base Forecast, and Table 5-54 for the PVWatts Forecast.

Table 5-52. Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,531
2028	0	0	0	50,808
2033	0	0	0	52,705
2038	0	0	0	54,602
2043	0	0	0	56,499
2048	0	0	0	58,396

Table 5-53. Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,908
2022	0	0	0	49,636
2028	0	0	0	52,664
2033	0	0	0	55,188
2038	0	0	0	57,711
2043	0	0	0	60,235
2048	0	0	0	62,758

Table 5-54. Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,531
2028	0	0	0	50,808
2033	0	0	0	50,455
2038	0	0	0	52,037
2043	0	0	0	53,618
2048	0	0	0	55,199

5.3.7.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-55 for the Effective PV Forecast, Table 5-56 for the Spatial Base Forecast, and Table 5-57 for the PVWatts Forecast.

Table 5-55. Centralized BESS N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	26,492 ~~39,866~~	127,935	2,138 ~~2,150~~
2028	0	0	0	81,951 ~~100,979~~	133,688	2,765 ~~2,781~~
2033	0	0	0	123,478 ~~151,907~~	139,702	3,483 ~~3,504~~
2038	0	0	0	165,004 ~~202,835~~	145,991	4,337 ~~4,362~~
2043	0	0	0	206,531 ~~253,763~~	151,619	5,136 ~~5,166~~
2048	0	0	0	248,058 ~~304,690~~	155,733	5,738 ~~5,772~~

Table 5-56. Centralized BESS N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~39,866~~ 26,492	129,095	2,253
2022	0	0	0	32,545 ~~52,459~~	131,322	2,486
2028	0	0	0	68,868 ~~128,019~~	140,388	3,577
2033	0	0	0	99,136 ~~190,985~~	147,622	4,567
2038	0	0	0	129,405 ~~253,952~~	154,744	5,595
2043	0	0	0	159,674 ~~316,918~~	161,142	6,584
2048	31	7	4	189,942 ~~379,885~~	166,580	7,466

Table 5-57. Centralized BESS N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	~~39,866~~ 26,491	127,935	2,138
2028	0	0	0	~~57,449~~ 47,161	133,688	2,765
2033	0	0	0	64,385 ~~72,101~~	133,840	2,780

2038	0	0	0	~~86,753~~81,609	139,065	3,404
2043	0	0	0	~~101,405~~98,833	143,845	4,047
2048	0	0	0	116,058	147,226	4,516

In analyzing the Centralized BESS in Valley South Project, the following constraints (Table 5-58) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-58, only thermal violations associated with each constraint are reported.

Table 5-58. List of Centralized BESS in Valley South Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Valley EFG-Tap 22 #1	N-1	Valley EFG-Newcomb	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Moraga-Tap 150	N-1	Skylark-Tenaja	2048	-	-

5.3.7.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Centralized BESS in Valley South Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and the Centralized BESS in Valley South.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-59 for the three forecasts.

Table 5-59. Cumulative Benefits – Centralized BESS in Valley South

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	52,822	50,796	67,206
N-1	LAR (MWh)	6,375	21,684	~~73,275~~75,132
N-1	IP (MW)	467	780	1,375
N-1	PFD (hr)	1,320	1,999	3,456
N-1	Flex-1 (MWh)	~~2,757,800~~2,938,356	~~3,190,086~~4,067,234	~~21,406,139~~10,993,065
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	834	~~1,487~~2,111	5,182

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Centralized BESS in Valley South Project. The project provides significant relief addressing the N-0 and N-1 needs in the Valley South System. However, the solution does not offer any flexibility in terms of system tie-lines and capabilities to support planned, unplanned, or emergency conditions in the system. The batteries alone cannot complement the system needs during HILP events since they are not configured to operate as microgrids, nor are they a viable alternative to system tie-lines for extended events of extended duration.

5.3.7.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South transformer is avoided in the near-term and long-term horizon. Across all sensitivities, the benefits range from 22.7 to 140.9 GWh of avoided LAR.
2. Minimal N-1 overloads are observable in the long-term horizon for all forecasts. With the project in service, the N-1 LAR benefits in the system range from 6.3 to 73.2 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Due to HILP events affecting Valley Substation, the project is unable to serve incremental load in the Valley South System. The BESS installed capacity cannot be effectively be translated to any benefits due to limited opportunities for charging that could reasonably be expected during HILP events.
5. Overall, the Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. While the project addressed N-0 and N-1 needs across the horizon, the solution offers limited flexibility benefits with higher implementation costs.

5.3.8 Valley South to Valley North and Distributed BESS in Valley South project (Project I)

The objective of this project is to transfer Newcomb and Sun City Substations to Valley North (identical to Project F) along with the procurement of distribution-system connected BESS (utility-scale DER) in the Valley South System. In this analysis, a load transfer from the Valley South System to the Valley North System precedes the investment in a distributed BESS. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North System, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast under study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.8.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North system through new 115 kV construction and reconfiguration.
2. Normally-open circuit breakers at the Valley South system bus and at Sun City Substation are maintained as system tie-lines between the Valley North system and the Valley South System for transfer flexibility.
3. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The initial need year is identified as 2036 and 2043 in the Spatial Base and Effective PV Forecasts, respectively. No procurements are required in the PVWatts Forecast.
4. Storage investments totaling 50 MW are made at Auld, Elsinore, and Moraga Substations, which have been identified as having sufficient space to likely accommodate on-site BESS installations. The 50 MW total of BESS was modeled as 10 MW at Auld, 20 MW at Elsinore, and 20 MW at Moraga Substation.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-10 presents a high-level representation of the proposed configuration.

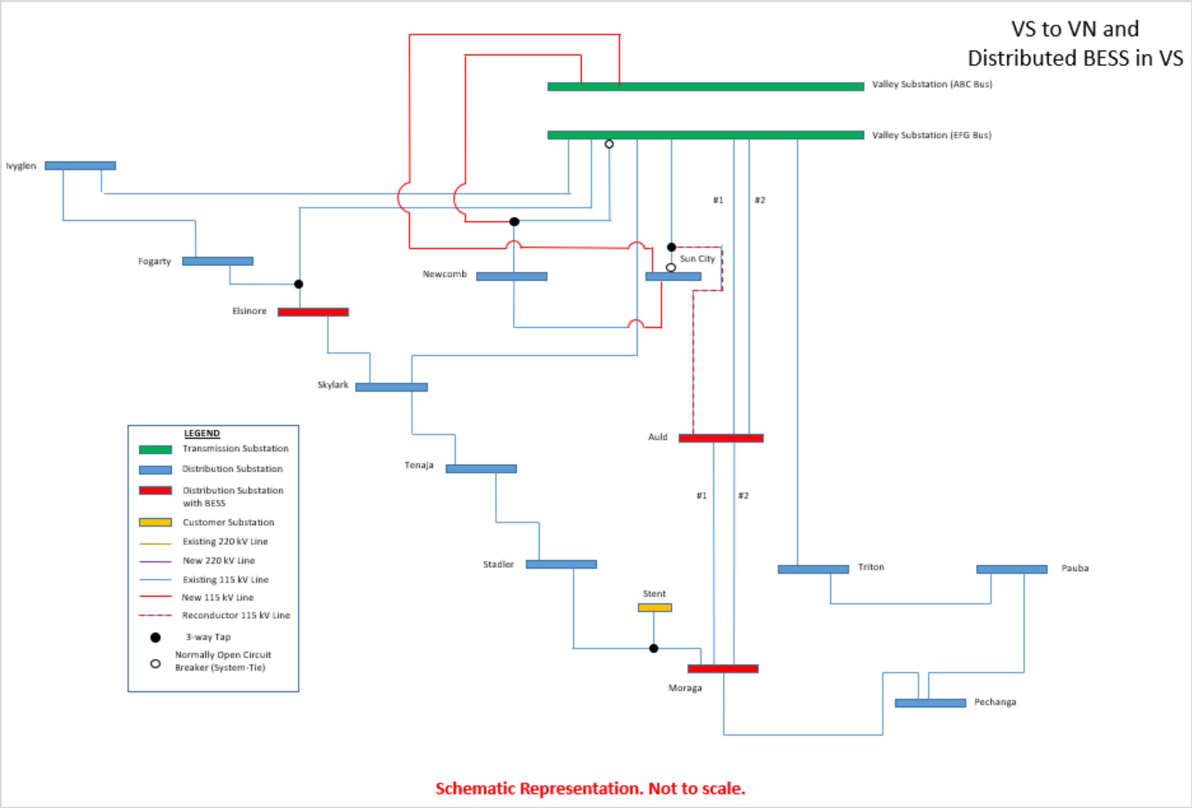


Figure 5-10. Tie-lines between Valley South and Valley North and Distributed BESS in Valley South Project Scope

5.3.8.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-60 for the Effective PV Forecast, Table 5-61 for the Spatial Base Forecast, and Table 5-62 for the PVWatts Forecast.

Table 5-60. Valley South to Valley North and Distributed BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	136	14	4	55,858
2043	775	43	19	57,898
2048	2,567	156	57	59,923

Table 5-61. Valley South to Valley North and Distributed BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	305	56	13	56,568
2038	2,388	143	51	59,310
2043	7,789	253	102	62,034
2048	16,127	371	159	64,749

Table 5-62. Valley South to Valley North and Distributed BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	94	49	6	54,713
2048	750	202	19	56,399

5.3.8.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-63 for the Effective PV Forecast, Table 5-64 for the Spatial Base Forecast, and Table 5-65 for the PVWatts Forecast.

Table 5-63. Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,330~~17,489~~	127,935	571
2028	0	0	0	44,298	133,688	843
2033	4	2	2	68,743~~66,640~~	139,702	1,161
2038	103	14	19	92,170 ~~88,981~~	145,991	1,586
2043	324	18	45	113,095~~111,322~~	151,619	2,025
2048	614	23	80	~~133,664~~134,586	155,733	2,370~~2,366~~

Table 5-64. Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~17,489~~21,331	129,095	616
2022	0	0	0	27,808~~70,726~~	131,322	715
2028	4	2	2	66,672~~390,153~~	140,388	1,202
2033	156	18	22	99,058~~656,341~~	147,622	1,710
2038	488	23	69	131,445~~922,530~~	154,744	2,247
2043	1357	33	155	163,831~~1,188,719~~	161,142	2,823
2048	2506	65	243	196,218~~1,454,907~~	166,580	3,320

Table 5-65. Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331 ~~17,489~~	127,935	571
2028	0	0	0	46,816 ~~43,874~~	133,688	843
2033	0	0	0	68,054 ~~65,861~~	133,840	850
2038	0.4	0.4	1	89,293~~87,849~~	139,065	1,122
2043	47	10	11	110,530 ~~109,836~~	143,845	1,426
2048	138	17	22	131,768~~131,824~~	147,226	1,679

In analyzing the Valley South to Valley North and Distributed BESS in Valley South Project, the following constraints (Table 5-66) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from 2022 and beyond).

In Table 5-66, only thermal violations associated with each constraint are reported.

Table 5-66. List of Valley South to Valley North and Distributed BESS in Valley South project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley North Transformer	N-0	N/A (base case)	2030		-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	-	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	2043	-
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2033	-

5.3.8.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North and Distributed BESS in Valley South Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the project for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-67 for the three forecasts.

Table 5-67. Cumulative Benefits – Valley South to Valley North and Distributed BESS in Valley South

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,245.60	27,277.58
N-1	LAR (MWh)	5,724	17,090.60	~~55,520.05~~57,832
N-1	IP (MW)	366	526.95	790.25
N-1	PFD (hr)	1,196	1,389	1,459
N-1	Flex-1 (MWh)	~~2,847,054~~2,275,927	~~5,801,041~~5,741,522	~~6,669,106~~10,977,462
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,405~~8~~	88,541
N-0	LAR (MWh)	20,124	45,854	45,131

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	IP (MW)	1,910	3,416	2,967
N-0	PFD (hr)	328	561	330

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North and Distributed BESS in Valley South Project. By design, the project includes a permanent transfer of large load centers from the Valley South System during the initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. The presence of a distributed BESS solution in the Valley South System alleviates the capacity needs in the Valley South System in the Effective PV Forecast, but not under the Spatial Base Forecast sensitivity. Additionally, the transformer overload condition is propagated to the Valley North System transformers beginning in the year 2030 in the Spatial Base Forecast.

5.3.8.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloads on the Valley South System transformers are avoided in the near-term and long-term horizon until the year 2033. However, the transfer of loads results in overloads on the Valley North System transformers by the year 2037. Under N-0, 2,600 MWh of LAR is recorded in the Effective PV Forecast for 2048, and 16,200 MWh is recorded under the Spatial Base Forecast sensitivity. Across all sensitivities, the benefits range from 20.1 to 45.1 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 5.7 GWh to 55 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Should a HILP event affect Valley Substation, this solution is unable to serve incremental load in the Valley South system by leveraging the capabilities of system tie-lines. Additionally, the BESS capacity cannot be effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.
5. Overall, the Valley South to Valley North and Distributed BESS in Valley South Project did not demonstrate comparable levels of performance in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.9 SDG&E and Centralized BESS in Valley South (Project J)

This project proposes to construct a new 230/115 kV substation provided power by the SDG&E transmission system (identical to Project B). This solution is coupled with Centralized BESS in Valley South (identical to Project H) to provide further relief over the long-term horizon. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.9.1 Description of Project Solution

The proposed project would transfer Pechanga and Pauba Substations to a new 230/115 kV transmission substation receiving 230 kV service from the SDG&E electric system. The proposed project would include the following components:

1. The point of interconnection would be a new 230/115 kV substation between the SCE-owned Pechanga Substation and SDG&E-owned Talega–Escondido 230 kV transmission line to the south. Two 230/115 kV transformers (one load-serving and one spare).
2. New double-circuit 230 kV transmission line looping the new substation into SDG&E's Talega–Escondido 230 kV transmission line.
3. New 115 kV line construction to allow the transfer of Pechanga and Pauba Substations from Valley South to new 230/115 kV substation.
4. Create system tie-lines between the new 230/115 kV system and the Valley South System through normally-open circuit breakers at SCE's Triton and Moraga Substations to provide operational flexibility and to accommodate potential future additional load transfers.
5. Rebuild of existing Pechanga Substation and/or expansion of existing property at Pechanga Substation to accommodate required new 115 kV switch rack positions.
6. BESS would be installed near Auld Substations following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
7. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-68 through Table 5-70, for all forecasts.
8. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026).
9. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-68. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	MW	MWh
2039	65	189
2044	25	130
Total Battery Size (including contingency): **90 MW/319 MWh**		

Table 5-69. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	MW	MWh
2033	82	262
2038	56	323
2043	49	323
Total Battery Size (including contingency): **187 MW/908 MWh**		

Table 5-70. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	MW	MWh
2048	20	64
Total Battery Size (including contingency): **20 MW/64 MWh**		

Figure 5-11 presents a high-level representation of the proposed configuration.

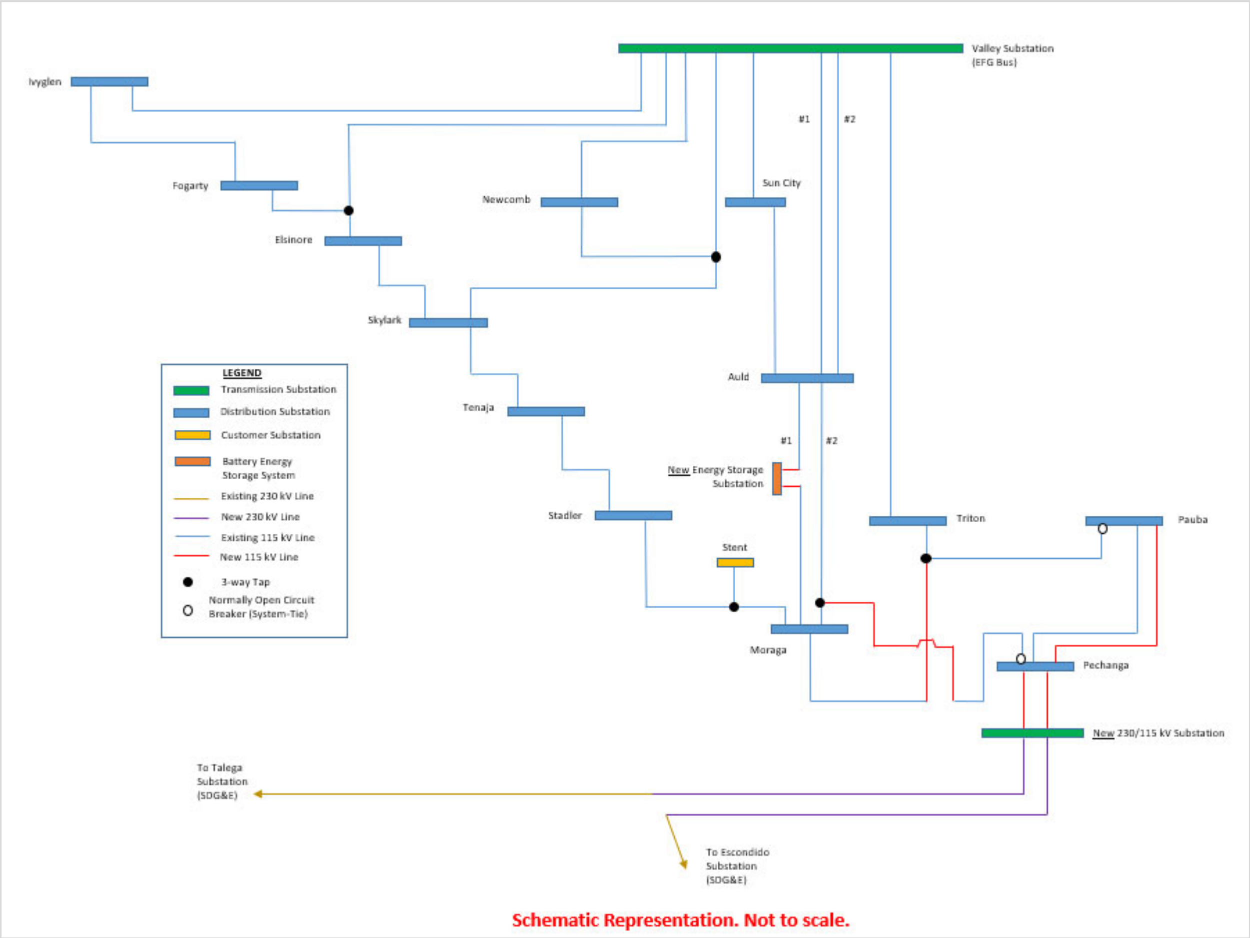


Figure 5-11. SDG&E and Centralized BESS in Valley South Project Scope

5.3.9.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions in the system are presented in Table 5-71 for the Effective PV Forecast, Table 5-72 for the Spatial Base Forecast, and Table 5-73 for the PVWatts Forecast.

Table 5-71. SDG&E and Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	48,529
2038	0	0	0	50,505
2043	0	0	0	51,023
2048	0	0	0	51,176

Table 5-72. SDG&E and Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	44,182
2022	0	0	0	44,715
2028	0	0	0	46,963
2033	0	0	0	48,837
2038	0	0	0	50,687
2043	0	0	0	52,537
2048	0	0	0	54,387

Table 5-73. SDG&E and Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	45,310
2038	0	0	0	46,470
2043	0	0	0	47,630
2048	0	0	0	48,790

5.3.9.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 5-74 for the Effective PV Forecast, Table 5-75 for the Spatial Base Forecast, and Table 5-76 for the PVWatts Forecast.

Table 5-74. SDG&E and Centralized BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	16,761	15,152	428~~431~~
2028	0	0	0	42,455	17,895	636 ~~639~~
2033	0	0	0	63,537 ~~63,867~~	21,123	926 ~~932~~
2038	0	0	0	84,920 ~~85,279~~	24,949	1,274~~1,282~~
2043	0	0	0	106,303~~106,690~~	28,757	1,662~~1,672~~
2048	0	0	0	128,102	31,740	1,977~~1,990~~

Table 5-75. SDG&E and Centralized BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	16,761	15,677	468
2022	0	0	0	~~29,302~~22,124	16,727	545
2028	0	0	0	54,299~~104,551~~	21,517	958
2033	0	0	0	81,112~~167,259~~	26,018	1,380
2038	0	0	0	107,924~~229,966~~	31,008	1,889
2043	0	0	0	134,737~~292,674~~	35,874	2,409
2048	0	0	0	161,550~~355,381~~	40,207	2,924

Table 5-76. SDG&E and Centralized BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	16,761	15,152	428
2028	0	0	0	33,355	17,895	636
2033	0	0	0	47,182	17,971	641
2038	0	0	0	61,010	20,763	896
2043	0	0	0	74,838	23,589	1,146
2048	0	0	0	88,666	25,756	1,352

In analyzing the SDG&E and Centralized BESS in Valley South project, no constraints were found to be binding under N-0 and N-1 conditions.

5.3.9.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the SDG&E and Centralized BESS in Valley South to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the SDG&E and Centralized BESS for each of the metrics.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-77 for the three forecasts.

Table 5-77. Cumulative Benefits – SDG&E and Centralized BESS

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	195,515	214,367	249,947
N-1	LAR (MWh)	6,375	21,684	~~73,367~~76,225
N-1	IP (MW)	467	780	1,397
N-1	PFD (hr)	1,320	1,999	3,468
N-1	Flex-1 (MWh)	~~236,636~~3,439,502	~~519,519~~5,894,261	~~667,575~~11,526,786
N-1	Flex-2-1 (MWh)	~~3,439,502~~3,167,267	~~5,885,944~~3,217,646	~~22,072,661~~3,402,545
N-1	Flex-2-2 (MWh)	65,442	76,689~~509~~	97,285
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SDG&E and Centralized BESS in Valley South Project. With the BESS investments, the range of benefits is substantial in the N-1 category and N-0 category. However, the flexibility benefits offered by the solution are limited in comparison to the ASP.

5.3.9.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the near-term and long-term horizon. This trend is observable across all considered forecasts. Across all sensitivities, the benefits range from 22.7 to 140.9 GWh of avoided LAR.

2. With SDG&E and Centralized BESS in Valley South Project in service, the N-1 LAR benefits in the system range from 6.3 to 73.3 GWh through all forecasts. With the incremental investment in BESS, no N-1 overloads were observed in the system.
3. The project provides considerable flexibility to address planned and unplanned or emergency outages in the system while also providing benefits to address needs under the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.
4. Should a HILP event occur and impact Valley Substation, the SDG&E and Centralized BESS in Valley South Project can recover approximately 280 MW of load in the Valley South System by leveraging the capabilities of its system tie-lines. The BESS installed capacity alone cannot be effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.
5. Overall, the SDG&E and Centralized BESS Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in combination with storage investments.

5.3.10 Mira Loma and Centralized BESS in Valley South project (Alternatives K)

The objective of this alternative is to take advantage of the Mira Loma system to provide a new source of supply into the Valley South service area. To address capacity needs across the 30-year horizon, this solution is coupled with Centralized BESS in Valley South. This is essentially a combination of Projects E and H. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.10.1 Description of Project Solution

1. Construct a new 220/115 kV substation with two transformers (including a spare) and associated facilities. The substation would be located near SCE's existing Mira Loma Substation and would be provided power by looping in an existing 220 kV line. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
2. Transfer load at Ivyglen and Fogarty Substations from the Valley South System to the new 220/115 kV System created.
3. Creates two system tie-lines between Valley South and the new system at Valley Substation and Fogarty Substation, respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
6. BESS would be installed near Pechanga or Auld Substations following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
7. The initial BESS would be constructed near Pechanga Substation with an ultimate design capacity of 200 MW. Once this maximum value is reached, a subsequent and similar installation would be constructed near Auld Substation.

8. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-78 through Table 5-80, for all forecasts.
9. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026).
10. Due to the radial design of the Valley South system under the study, locating the BESS interconnection near Pechanga or Auld Substations would not result in significant differences to N-0 system performance and reliability indices.
11. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-78. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	MW	MWh	MW	MWh
2026	99	299		
2031	52	373		
2036	61	463		
2041			54	427
2046			18	157
Total Battery Size: **284 MW/ 1719 MWh**				

Table 5-79. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2031	83	247
2036	48	303
2041	43	296
2046	12	106
Total Battery Size: **186 MW/ 952 MWh**		

Table 5-80. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2036	66	195
2041	34	194
2046	9	62
Total Battery Size: **109 MW/ 451 MWh**		

Figure 5-12 presents a high-level representation of the proposed configuration.

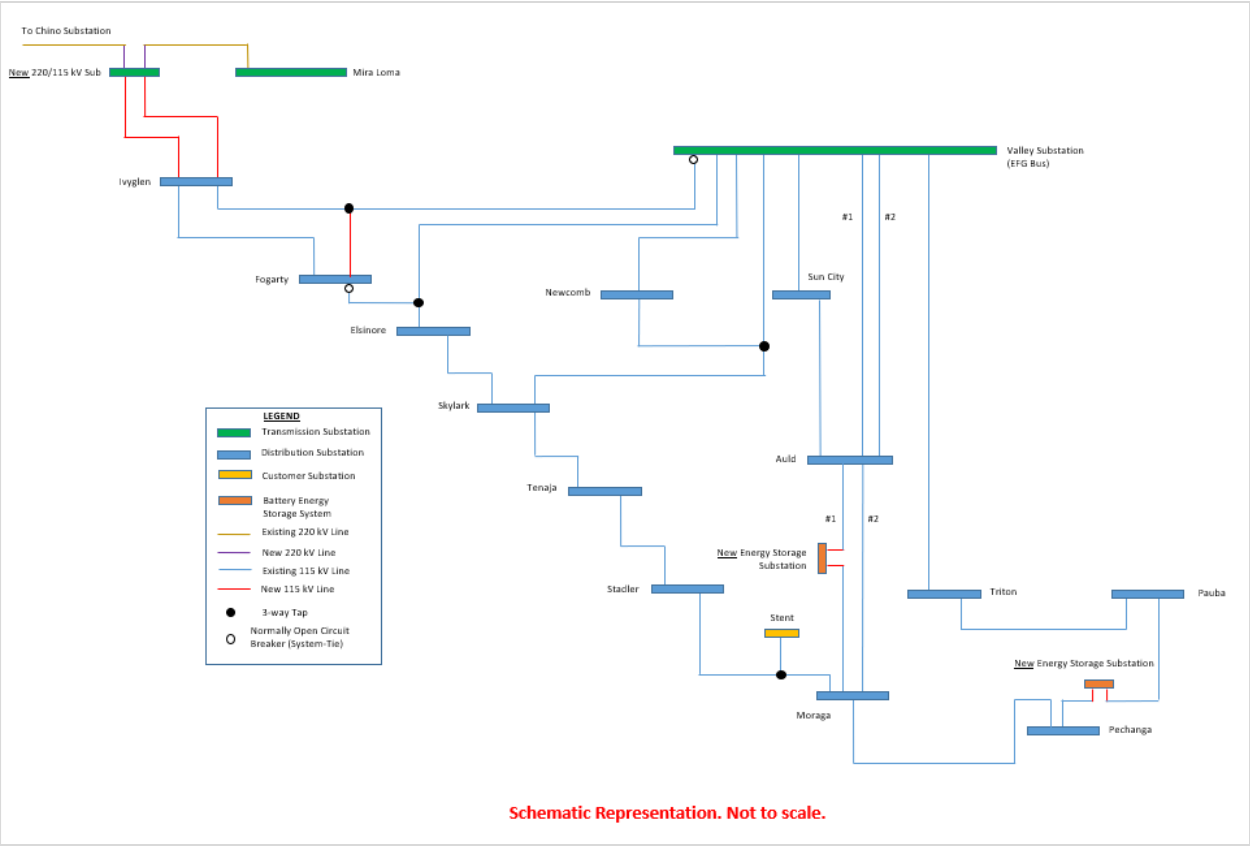


Figure 5-12. Tie-line to Mira Loma and Centralized BESS in Valley South Project Scope

5.3.10.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-81 for the Effective PV Forecast, Table 5-82 for the Spatial Base Forecast, and Table 5-83 for the PVWatts Forecast.

Table 5-81. Mira Loma and Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,456
2028	0	0	0	48,017
2033	0	0	0	50,408
2038	0	0	0	53,323
2043	0	0	0	56,238
2048	0	0	0	59,154

Table 5-82. Mira Loma and Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,849
2022	0	0	0	49,618
2028	0	0	0	42,629
2033	0	0	0	48,041
2038	0	0	0	53,453
2043	0	0	0	58,864
2048	0	0	0	64,276

Table 5-83. Mira Loma and Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	0	0	0	53,021
2038	0	0	0	55,097
2043	0	0	0	57,173
2048	0	0	0	59,250

5.3.10.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 5-84 for the Effective PV Forecast, Table 5-85 for the Spatial Base Forecast and Table 5-86 for the PVWatts Forecast.

Table 5-84. Mira Loma and Centralized BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	34,120~~24,348~~	82,321	650~~654~~
2028	0	0	0	87,130~~61,672~~	87,598	944~~949~~
2033	0	0	0	130,912~~92,776~~	91,967	1,299~~1,230~~
2038	0	0	0	174,909~~123,879~~	98,884	1,766~~1,777~~
2043	5	2.5	2	218,906~~154,983~~	104,047	2,217~~2,230~~
2048	15.2	2.5	9	262,902~~186,086~~	107,821	2,602~~2,617~~

Table 5-85. Mira Loma and Centralized BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~24,348~~34,121	83,384	708
2022	0	0	0	43,257~~69,128~~	85,427	828
2028	0	0	0	98,075~~337,812~~	93,744	1,345
2033	0	0	0	143,757~~561,716~~	100,380	1,885
2038	11	3	6	189,439~~785,619~~	106,913	2,508
2043	35	4	20	253,121~~1,009,523~~	112,783	3,132
2048	182	11	61	280,803~~1,233,426~~	117,771	3,729

Table 5-86. Mira Loma and Centralized BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	34,120~~24,348~~	82,321	650
2028	0	0	0	86,222~~178,252~~	87,598	944
2033	0	0	0	129,639~~123,172~~	87,737	951
2038	0	0	0	173,057~~168,092~~	92,531	1,259

2043	0	0	0	216,474~~213,012~~	96,915	1,601
2048	0	0	0	259,892~~257,932~~	100,017	1,852

In analyzing the Mira Loma and Centralized BESS in Valley South project, the following constraints (Table 5-87) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-87, only thermal violations associated with each constraint are reported.

Table 5-87. List of Mira Loma and Centralized BESS in Valley South Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley EFG-Tap 39 #1	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore #1	N-1	Valley EFG-Newcomb-Skylark	2043	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2038	2048	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Valley EFG-Tap 22#1	N-1	Valley EFG-Newcomb	2048	-	-

5.3.10.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Mira Loma and Centralized BESS in Valley South Project to quantify the overall benefits accrued over 30-year study horizons. The benefits are quantified as the difference between the baseline and the project for each of the metrics.

The accumulative values of the benefits over the 30-year horizon are presented in Table 5-88 for the three forecasts.

Table 5-88. Cumulative Benefits – Mira Loma and Centralized BESS in Valley South

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	50,251	41,338	51,951
N-1	LAR (MWh)	6,375	21,303	72,541~~83~~
N-1	IP (MW)	467	760	1,333
N-1	PFD (hr)	1,320	1,962	3,152
N-1	Flex-1 (MWh)	~~1,052,000~~893,598	~~5,000,736~~3,831,571	~~9,673,818~~9,614,215

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-1	Flex-2-1 (MWh)	1,252,410	1,263,410	1,326,687
N-1	Flex-2-2 (MWh)	55,850	~~64,946~~65,194	82,304
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Mira Loma and Centralized BESS in Valley South Project. The project completely addresses N-0 needs in the Valley South System. The capacity afforded by the system tie-lines does not fully support emergency and maintenance conditions in the system.

5.3.10.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the study horizon. This trend is observable across all considered forecasts. Across all sensitivities, the benefits range from 22.7 to 140.9 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 6.3 to 72.5 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that may occur in the Valley South System.
4. Should a HILP event occur and impact Valley Substation, the Mira Loma and Centralized BESS in Valley South Project can recover approximately 110 MW of load in the Valley South System by leveraging the capabilities of its system tie-lines. The BESS installed capacity alone cannot be effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.
5. Overall, the Mira Loma and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers a limited advantage in addressing the N-1 and flexibility needs of the system.

5.3.11 Valley South to Valley North and Centralized BESS in Valley South and Valley North (Project L)

The objective of this project would be to transfer the loads at Newcomb and Sun City substations to Valley North (identical to Project #F). Additionally, BESS installation would be constructed within both the Valley South and Valley North systems to provide relief over the long-term horizon. This is a combination of Projects F and H. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North system have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.11.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through the construction of new 115 kV lines.
2. Normally-open circuit breakers at the Valley South bus and at Sun City Substation are maintained as system tie-lines between Valley North and Valley South for transfer flexibility.
3. Reconductor existing Auld–Sun City 115 kV line, which would become the Valley–Auld–Sun City 115 kV line.
4. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
5. BESS would be installed near Pechanga in Valley South and Allesandro Substation in Valley North following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
6. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-89 through Table 5-91, for all forecasts.
7. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026).
8. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-89. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	MW	MWh	MW	MWh
2030			97	375
2035(VS-2036)	81	242	77	635
2042 (VS-2041)	49	291	72	704
2045(VS-2046)	18	114	39	418
Total Battery Size: **433 MW/ 2779 MWh**				

Table 5-90. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

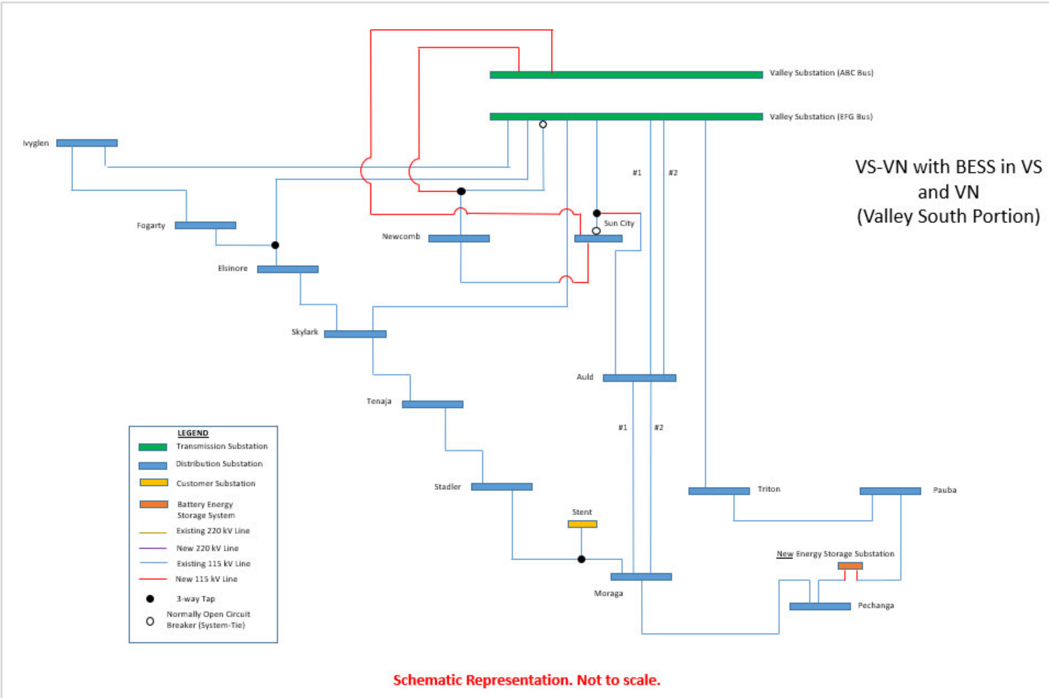
Year	Total Battery Size	
	Pechanga (VS)	Alessandro (VN)

	MW	MWh	MW	MWh
2037			83	290
2042 (VS-2043)	39	108	46	335
2046	10	42	18	165
Total Battery Size (including contingency): **196 MW/ 940 MWh**				

Table 5-91. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	MW	MWh	MW	MWh
2040	0	0	67	204
2045	0	0	27	140
Total Battery Size: **94 MW/ 344 MWh**				

Figure 5-13 presents a high-level representation of the proposed configuration.



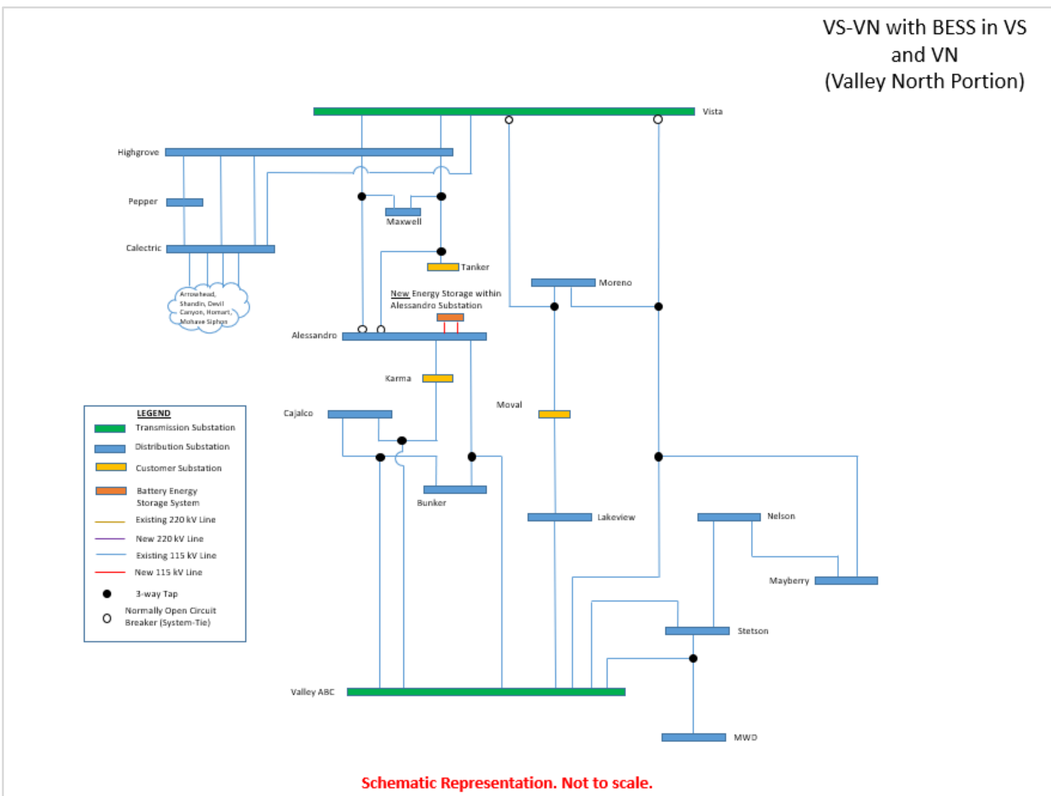


Figure 5-13. Valley South to Valley North and Centralized BESS in Valley South and Valley North

5.3.11.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions are presented in Table 5-92 for the Effective PV Forecast, Table 5-93 for the Spatial Base Forecast, and Table 5-94 for the PVWatts Forecast.

Table 5-92. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	0	0	0	55,858
2043	0	0	0	57,893
2048	0	0	0	59,910

Table 5-93. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	0	0	0	59,306
2043	0	0	0	62,024
2048	0	0	0	64,742

Table 5-94. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	0	0	0	56,399

5.3.11.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions are presented in Table 5-95 for the Effective PV Forecast, Table 5-96 for the Spatial Base Forecast, and Table 5-97 for the PVWatts Forecast.

Table 5-95. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331~~25,483~~	127,935	571~~574~~
2028	0	0	0	64,547	133,688	843~~848~~
2033	4	2	2	84,028~~97,100~~	139,702	1,161 ~~1,168~~
2038	103	14	19	116,572 ~~129,653~~	145,991	1,586~~1,596~~
2043	351	24	45	146,858 ~~162,206~~	151,619	2,025~~2,037~~
2048	506	27	73	194,760	155,733	2,366 ~~2,381~~

Table 5-96. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~25,483~~21,083	129,095	616
2022	0	0	0	25,681~~43,949~~	131,322	715
2028	4	3	2	53,273~~154,747~~	140,388	1,202
2033	156	19	22	72,267~~247,078~~	147,622	1,710
2038	445	23	66	99,260~~339,410~~	154,744	2,284
2043	1,063	29	135	122,253~~431,741~~	161,142	2,889
2048	1,845	76	205	145,246~~524,073~~	166,580	3,429

Table 5-97. Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331 ~~25,483~~	127,935	571
2028	0	0	0	46,816 ~~49,808~~	133,688	843

2033	0	0	0	68,054 ~~70,079~~	133,840	850
2038	0.4	0.4	1	89,2939 ~~0,350~~	139,065	1,122
2043	47	10	11	110,531 ~~110,622~~	143,845	1,426
2048	138	17	22	131,769 ~~130,893~~	147,226	1,679

In analyzing the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project, the following constraints (Table 5-98) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-98, only thermal violations associated with each constraint are reported.

Table 5-98. List of Valley South to Valley North and Centralized BESS in Valley South and Valley North Project System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2038	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.11.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the project for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 5-99 for the three forecasts.

Table 5-99. Valley South to Valley North and Centralized BESS in Valley South and Valley North Cumulative Benefits

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,322	27,375
N-1	LAR (MWh)	5,724	17,603	62,386~~59,548~~
N-1	IP (MW)	366	503	803
N-1	PFD (hr)	1,196	1,456	1,740
N-1	Flex-1 (MWh)	2,795,927 ~~2,751,701~~	5,140,766.57 ~~4,868,325~~	11,694,529 ~~19,588,877~~
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,408~~185~~	87,739
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project. By design, the project includes a permanent transfer of relatively large load centers in the Valley South System during the initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. The solution completely addresses the N-0 system needs in the Valley South and Valley North Systems.

5.3.11.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided in the near-term and long-term horizon. Additionally, the installation of batteries avoids the N-0 needs in the Valley North System following the transfer of load from the Valley South system. Across all sensitivities, the benefits range from 22.7 to 140.9 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, N-1 benefits in the system range from 5.7 to 59.54 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Should a HILP event occur and impact Valley Substation, the project is unable to serve incremental load in the Valley South System through leveraging the capabilities of its system tie-lines.
5. Overall, the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers a limited advantage in addressing the N-1 and flexibility needs of the system.

5.3.12 Valley South to Valley North to Vista and Centralized BESS in Valley South Project (Project M)

The objective of this project would be to transfer the loads at Newcomb and Sun City Substations to Valley North. The load at Moreno in the Valley North system would be transferred to the Vista system (identical to Project #G). The premise of this methodology is to relieve loading on the Valley North system to accommodate a load transfer from Valley South. Additionally, BESS is installed in Valley South to provide relief over the long-term horizon. This is essentially a combination of Projects G and H. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North System, however, transformer loading would be at risk of exceeding rated capacity. Due to this, only the LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.12.1 Description of Project Solution

The proposed project would include the following components:

1. Moreno Substation is transferred to Vista 220/115 kV system through existing system tie-lines between Valley North and Vista Systems.
2. New 115 kV line construction to restore subtransmission network connectivity following a transfer of Moreno Substation.
3. Normally-open circuit breaker at Moreno Substation to provide a system tie-line between the Vista and Valley North Systems.
4. The proposed project would also transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through the construction of new 115 kV lines (see Project F).
5. Normally-open circuit breakers at the Valley South bus and the Sun City Substation are maintained as system ties between the Valley North and Valley South Systems for transfer flexibility.
6. Reconductor existing Auld–Sun City 115 kV line, which would become the Valley–Auld–Sun City 115 kV line.
7. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
8. BESS would be installed near Pechanga Substation following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
9. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-100 and Table 5-101, for all forecasts. No batteries were required at Valley South in the PVWatts Forecast.
10. Sizing analysis has been performed for all forecasts on a 5-year outlook (i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026).
11. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

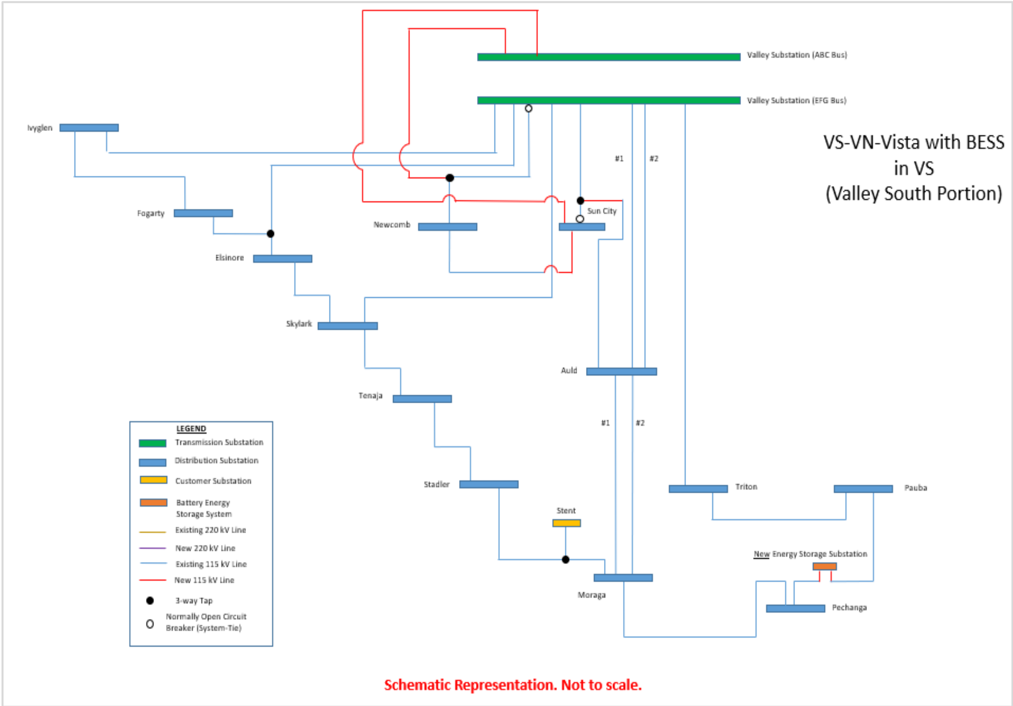
Table 5-100. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2036	81	242
2041	49	291
2046	18	114
Total Battery Size (including contingency): **148 MW / 647 MWh**		

Table 5-101. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2043	39	108
2046	10	42
Total Battery Size (including contingency): **49 MW / 150 MWh**		

Figure 5-14 presents a high-level representation of the proposed configuration.



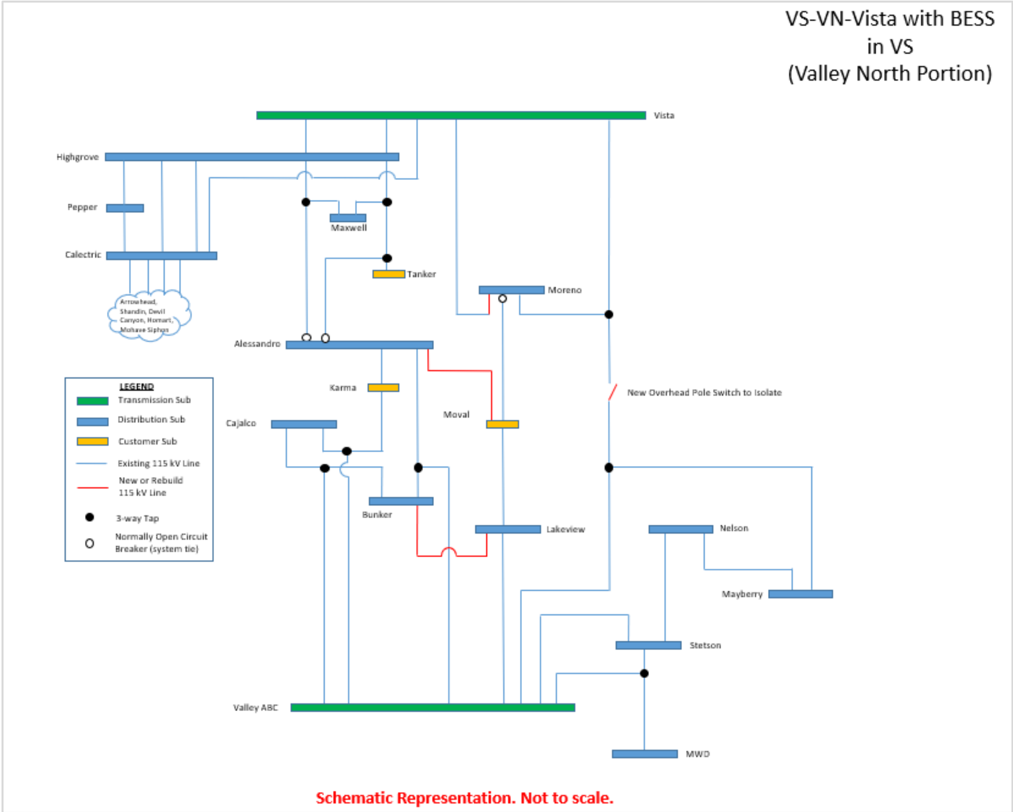


Figure 5-14. Valley South to Valley North to Vista and Centralized BESS in Valley South

5.3.12.2 System Performance under Normal Conditions (N-0)

Findings from the system analysis under N-0 conditions in the system are presented in Table 5-102 for the Effective PV Forecast, Table 5-103 for the Spatial Base Forecast, and Table 5-104 for the PVWatts Forecast.

Table 5-102. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	0	0	0	55,858
2043	78	30	5	57,893
2048	735	83	18	59,910

Table 5-103. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	676	81	17	59,306
2043	3416	162	58	62,024
2048	8000	232	103	64,742

Table 5-104. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	68	37	5	56,399

5.3.12.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 5-105 for the Effective PV Forecast, Table 5-106 for the Spatial Base Forecast, and Table 5-107 for the PVWatts Forecast.

Table 5-105. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331 ~~25,483~~	127,935	571 ~~574~~
2028	0	0	0	64,547 ~~64,547~~	133,688	843~~848~~
2033	4	2	2	84,028 ~~97,100~~	139,702	1,160~~1,168~~
2038	103	14	19	116,572 ~~129,653~~	145,991	1,586~~1,596~~
2043	351	24	45	146,858 ~~162,206~~	151,619	2,025 ~~2,037~~
2048	506	27	73	194,760	155,733	2,366 ~~2,381~~

Table 5-106. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (Spatial Base Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~25,483~~21,083	129,095	616
2022	0	0	0	25,681~~43,949~~	131,322	715
2028	4	3	2	53,273~~154,747~~	140,388	1,202
2033	156	19	22	76,267~~247,078~~	147,622	1,710
2038	445	23	66	99,260~~339,410~~	154,744	2,284
2043	1,063	29	135	122,253~~431,741~~	161,142	2,889
2048	1,845	76	205	~~524,073~~145,247	166,580	3,429

Table 5-107. Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (PVWatts Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	~~25,483~~21,330	127,935	571

2028	0	0	0	46,816 ~~49,808~~	133,688	843
2033	0	0	0	68,054 ~~70,079~~	133,840	850
2038	0.4	0.4	1	89,292 ~~90,350~~	139,065	1,122
2043	47	10	11	110,530 ~~110,622~~	143,845	1,426
2048	138	17	22	131,768 ~~130,893~~	147,226	1,679

In analyzing the Valley South to Valley North to Vista and Centralized BESS in Valley South Project, the following constraints (Table 5-108) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR among other reliability metrics under study (reported from need year and beyond).

In Table 5-108, only thermal violations associated with each constraint are reported.

Table 5-108. List of Valley South to Valley North to Vista and Centralized BESS in Valley South Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2038	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.12.4 Evaluation of Benefits

The established performance metrics were compared between the baseline and the Valley South to Valley North to Vista and Centralized BESS in Valley South Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the project for each of the metrics.

The accumulative values of the benefits over the 30-year horizon are presented in Table 5-109 for the three forecasts.

Table 5-109. Valley South to Valley North to Vista and Centralized BESS in Valley South Project Cumulative Benefits

Category	Component	Cumulative Benefits over 30-year Horizon (until 2048) *PVWatts Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Effective PV Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,322	27,375
N-1	LAR (MWh)	5,724	17,603	62,386~~59,548~~
N-1	IP (MW)	366	503	803
N-1	PFD (hr)	1,196	1,456	1,740
N-1	Flex-1 (MWh)	2,795,927 ~~2,751,701~~	5,140,766.57~~4,868,325~~	11,694,529~~19,588,877~~
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,408~~69,185~~	87,739
N-0	LAR (MWh)	22,613	54,062	96,778
N-0	IP (MW)	2,638	3,687	4,380
N-0	PFD (hr)	399	741	939

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North to Vista and Centralized BESS in Valley South Project. By design, the project includes a permanent transfer of relatively large load centers in the Valley South System during the initial years. This provides significant N-0 system relief in the Valley South System but at the expense of limited operational flexibility. The addition of batteries complements the needs in the Valley South System effectively reducing LAR to zero over the long-term horizon. The transfer of loads from the Valley North System to the Vista System avoid transformer overloads in Valley North until 2041.

5.3.12.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloads on the Valley South System transformers are avoided in the near-term and long-term horizon. Additionally, the transfer of loads from the Valley North System to the Vista System defers the N-0 condition needs in Valley North until 2041. Across all sensitivities, the benefits range between 22.6 to 96.7 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 0.6 to 30.2 GWh through all forecasts.
3. The project provides only limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Should a HILP event occur and impact Valley Substation, the project is unable to serve incremental load in the Valley South System by leveraging capabilities of its tie-lines.
5. Overall, the Valley South to Valley North to Vista and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers a limited advantage in addressing the N-1 and Flexibility needs of the system

5.4 Summary of Findings

Through the analysis of alternatives and applicable reliability metrics, LAR, and flexibility (Flex-1 and Flex-2) provide valuable insight into the reliability, capacity, resilience, and flexibility objectives of project performance. Table 5-110 through Table 5-112 present a summary of these findings across all forecasts.

Table 5-110. Cumulative Benefits: Effective PV Forecast

		Project ID												
Project Name		Alberhill System Project	San Diego Gas & Electric Project	Valley South to Valley North to Vista Project	Centralized BESS in Valley South Project	Mira Loma and Centralized BESS in Valley South Project	Valley South to Valley North and Distributed BESS in Valley South Project	Menifee Project	Mira Loma Project	SCE Orange County Project	Valley South to Valley North and Centralized BESS in Valley South and Valley North Project	Valley South to Valley North to Vista and Centralized BESS in Valley South Project	SDG&E and Centralized BESS in Valley South Project	Valley South to Valley North Project
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	20	21	15	21	21	17	15	15	17	18	18	21	15
N-2	**Available Flex-1**	6,024 ~~5,689~~	5,415~~5,411~~	5,357~~5,352~~	4,067~~3,190~~	3,831 ~~5,001~~	5,742~~5,801~~	5,357 ~~5,352~~	3,2554~~3,252~~	1,279~~448~~	5,141~~4,868~~	5,141~~4,868~~	5,894~~5,886~~	5,357~~5,352~~
N-2	**Available Flex-2-1**	3,780	3,218	-	-	1,263	-	2,368	1,263	3,256	-	-	3,218	-
N-2	**Available Flex-2-2**	107	77	69	1	65	69	69	65	81	69	69	77	69
N-0	**LAR**	57	56	54	57	57	46	56	50	56	57	54	57	45

Table 5-111. Cumulative Benefits: Spatial Base Forecast

		Project ID												
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	69~~7~~	76~~3~~	51~~48~~	~~73~~76	~~73~~76	~~56~~58	~~48~~51	~~43~~45	~~57~~60	~~60~~62	~~60~~62	~~73~~76	~~48~~51
N-2	**Available Flex-1**	9,665 ~~23,517~~	9,902~~19,117~~	9,662~~14,163~~	10,993~~21,406~~	9,614~~9,674~~	10,977~~6,669~~	9,662~~14,163~~	6,500~~6,363~~	4,209~~9,232~~	11,694~~19,589~~	11,694~~19,589~~	11,526~~22,073~~	9,662~~14,163~~
N-2	**Available Flex-2-1**	4,102	3,403	-	-	1,327	-	3,030	1,327	3,449	-	-	3,403	-
N-2	**Available Flex-2-2**	142	97	88	5	82	-	88	82	104	88	88	97	88
N-0	**LAR**	141	132	91	141	141	89	136	110	133	141	97	141	41

Table 5-112. Cumulative Benefits: PVWatts Forecast

		Project ID												
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	6	6	6	6	6	6	6	5~~3~~	5	6	6	6	6
N-2	**Available Flex-1**	~~3,901~~4,205	3,363	2,795	2,~~758~~939	~~1,052~~894	~~2,847~~2796	2,795	623	584	2,796~~52~~	~~2,752~~2,796	3,440	2,795
N-2	**Available Flex-2-1**	3,658	3,167	-	-	1,252	-	2,860	1,252	3,201	-	-	3,167	-
N-2	**Available Flex-2-2**	88	65	59	1	56	59	59	56	69	59	59	65	59
N-0	**LAR**	23	23	23	23	23	20	23	19	23	23	23	23	20

The following insights are established upon review of the project performance, system benefits, and overall needs in the Valley South System.

1. The Valley South System is vulnerable to the risk of unserved energy starting year 2022 under the Effective PV and PVWatts Forecasts and year 2021 under the Spatial Base Forecast. The Spatial Base Forecast assumes current levels of DER adoption persist through the long-term horizon, whereas the other two forecasts adopt DER consistent with IEPR 2018 forecasts.
2. The unserved energy in the Valley South System continues to grow beyond the 10-year planning horizon. This drives the need for solutions that are capable of supporting long-term load-growth trends in the Valley South System.
3. The load forecast includes the expected levels of peak reduction from DER technologies over the long-term horizon. The amount of relief offered by the expected levels were determined to be insufficient to meet the needs in the Valley South System service territory.
4. Dependency on NWA solutions (e.g., centralized storage) drives large investments and requires periodic upgrades to keep pace with the load-growth trend in the system. Although these solutions provide N-0 and N-1 relief, they offer limited flexibility to support planned, unplanned or emergency operations in the system (including N-2 outages and HILP events).
5. Dependency on neighboring systems (Valley North and Mira Loma) provides limited relief in terms of N-0 and N-1 benefits. While some solutions address the needs in the Valley South System, they aggravate the condition in the adjacent subtransmission system. For example, with a transfer of loads to Valley North, the risk of transformer overload significantly increases in the Valley North service territory. Additional transfers from Valley North to its neighbors provide limited relief over a long-term horizon. These solutions are also restricted by the capabilities of the neighboring system during peak loading conditions.
6. A combination of storage and tie-lines to neighboring systems provide improved benefits in comparison to stand-alone NWAs. These benefits are realized because tie-lines can be leveraged in combination with local storage capacity. However, these solutions were found to require large investments, while only contributing to N-0 objectives in the system. Although they offer improved flexibility and N-1 benefits, they are not sufficient to adequately meet all the needs in Valley South.
7. Wire-based alternatives offer the highest relief to meet the needs in the Valley South System. These solutions were found to adequately meet the range of forecast sensitivities while meeting the overall project objectives. Except for the projects that did not meet the objectives over the study horizon and those with significant implementation difficulty, wire-based alternatives offer the highest benefits.
8. In all considered forecasts, the ASP provided the highest aggregated benefits. Aggregated benefits are derived from the cumulative value of LAR and Flex Metrics that translate into capacity, reliability, resilience, and flexibility needs in the Valley South service area. The ASP consistently provides the highest aggregated benefits across all considered forecasts.
9. From a capacity perspective, the ASP, SDG&E, and Hybrid solutions (SDG&E and Centralized BESS in Valley South) provide the most relief. Taking into consideration the combination of flexibility and resilience needs, the ASP, Orange County Project, and SDG&E Project are the most preferable alternatives.

6 BENEFIT-COST ANALYSIS (BCA)

6.1 Introduction

The objective of this task was to perform a detailed benefit-cost and risk analysis of the ASP and alternative projects introduced in Section 5. This framework provides an additional basis for the comparison of project performance while justifying the business case of each alternative in meeting the load growth and reliability needs of the Valley South System.

The benefit is defined as the value of the impact of a project on a firm, a household, or society in general. This value can be either monetized or treated on a unit basis while dealing with reliability metrics like LAR, Interrupted Power, and Period of Flexibility Deficit among other considerations. Net benefits are the total reductions in costs and damages as compared to the baseline, accruing to firms, customers, and society at large, excluding transfer payments between these beneficiary groups. All future benefits and costs are reduced to a present worth (NPV) using a discount rate, and an inflation rate, over the project lifetime.

Following the quantification of the present worth of costs and benefits (Sections 4 and 5), three different types of analysis have been considered to provide a comprehensive view of the value attributed to each project. These are traditional BCA, $/unit benefit analysis, and incremental BCA. These analyses use non-monetized and monetized benefits consistent with the methodology described in Section 3.3 over the 30-year study horizon.

6.2 Benefit-Cost Calculation Spreadsheet

All the findings within this section are maintained in a spreadsheet outlining the calculations and associated costs. Hence, three spreadsheets[11] are provided that cover three study forecasts (Spatial Base, Effective PV, and PVWatts). These spreadsheets are provided with this submission.

The key elements within the spreadsheet are addressed in individual tabs are briefly introduced.

- Summary
  - Summarizes the study results and findings.
- Incremental Benefit-Cost Analysis
  - Results and rankings from the incremental benefit-cost analysis.
- Cost Assumptions
  - Outlines the key study inputs and assumptions.
- Baseline System Analysis
  - Raw reliability Indices.
  - The monetized value of the baseline reliability metrics.

[11] The three Excel spreadsheets are attached to this report.

Each spreadsheet address the following information as an individual tab for each alternative project.

- Benefit-cost Quantification to Baseline System
  - Raw reliability indices.
  - The monetized value of project reliability metrics.
  - Comparison of each project against baseline system performance.

6.3 Results from Benefit-Cost Analysis

The benefit-cost analysis is performed for all three forecasts under consideration, consistent with the methodology described in Section 3.3, and the study results for the following 13 alternative projects are present.

A. Alberhill System
B. San Diego Gas & Electric
C. SCE Orange County
D. Menifee
E. Mira Loma
F. Valley South to Valley North
G. Valley South to Valley North to Vista
H. Centralized BESS in Valley South
I. Valley South to Valley North and Distributed BESS in Valley South
J. SDG&E and Centralized BESS in Valley South
K. Mira Loma and Centralized BESS in Valley South
L. Valley South to Valley North and Centralized BESS in Valley South and Valley North
M. Valley South to Valley North to Vista and Centralized BESS in Valley South

6.3.1 Projects' Cost

The cost for each project is provided by SCE, in the PVRR and Aggregated (Total Capital Expenditure) representation. The PVRR costs include the investment costs and project expenses and calculated using the applicable discount rate. The cost of components associated with the design of projects is aggregated to develop the Total capital expenditure. For projects that include BESS, the PVRR costs are offset by revenues generated from market participation. Information regarding the scope of the projects has been summarized in Sections 4 and 5.

Table 6-1 provides the present worth and aggregated costs associated with each project. For BESS-based solutions, the cost varies as a function of the forecast under study. Table 6-2 provides the present worth of market participation revenues for the BESS-based solution.

Table 6-1. Project Cost (PVRR and Capex)

#	Project	Effective PV Forecast		Spatial Base		PVWatts	
		Present Worth ($M)	Aggregated ($M)	Present Worth ($M)	Aggregated ($M)	Present Worth ($M)	Aggregated ($M)
A	Alberhill System Project	$474	$545	$474	$545	$474	$545
B	SDG&E	$453	$540	$453	$540	$453	$540
C	SCE Orange County	$748	$951	$748	$951	$748	$951
D	Menifee	$331	$396	$331	$396	$331	$396
E	Mira Loma	$309	$369	$309	$365	$309	$365
F	Valley South to Valley North	$207	$221	$207	$221	$207	$221
G	Valley South to Valley North to Vista	$290	$317	$290	$317	$309	$365
H	Centralized BESS in Valley South	$525	$1,474	$848	$2,363	$381	$1,004
I	Valley South to Valley North and Distributed BESS in Valley South	$232	$326	$228	$354	$200	$218
J	SDG&E and Centralized BESS in Valley South	$531	$923	$658	$1,473	$479	$685
K	Mira Loma and Centralized BESS in Valley South	$560	$1,396	$601	$2,194	$448	$920
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	$1,172	$700	$2,616	$255	$572
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	$505	$404	$986	$269	$307

Table 6-2. Present Worth of Market Participation Revenues

Wholesale Energy and Ancillary Service markets				
#	Project	Effective PV Forecast	Spatial Base	PVWatts
		Present Worth of Market Participation Revenue ($M)	Present Worth of Market Participation Revenue ($M)	Present Worth of Market Participation Revenue ($M)
H	Centralized BESS in Valley South	$70	$109	$47
I	Valley South to Valley North and Distributed BESS in Valley South	$2	$5	-
J	SDG&E and Centralized BESS in Valley South	$5	$19	-
K	Mira Loma and Centralized BESS in Valley South	$25	$57	$8
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$12	$57	$4
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2	$11	-

Capacity and Resource Adequacy Markets				
#	Project	Effective PV Forecast	Spatial Base	PVWatts
		Present Worth of Market Participation Revenue ($M)	Present Worth of Market Participation Revenue ($M)	Present Worth of Market Participation Revenue ($M)
H	Centralized BESS in Valley South	$48,515	$74,932	$34,058
I	Valley South to Valley North and Distributed BESS in Valley South	$863	$2,105	-
J	SDG&E and Centralized BESS in Valley South	$3,579	$13,712	-
K	Mira Loma and Centralized BESS in Valley South	$18,124	$36,287	$6,395
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$10,185	$37,148	$2,798
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,000	$7,841	-

6.3.2 Baseline System Analysis

From the baseline system, the raw reliability indices computed in Section 4.2 are reflective of the overall impact on customers in the Valley South service territory. The monetization of EENS and Flexibility benefits demonstrate the aggregated cost impact to customers in the region. All benefits have been monetized consistent with the methodology outlined in Section 3.3 and derived as present worth. Table 6-3 presents the aggregated costs, taking into consideration the combination of Residential, Small & Medium Business and Commercial & Industrial customers.

Table 6-3. Baseline System Monetization

Category	Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Monetized Value for EENS - N-1	12~~8,357~~6,010	~~436~~428,~~189~~178	35,~~182~~200
Monetized Value for EENS - – N-0	2,530,518,587	~~6,000,480,385~~5,999,276,476	1,029,268,277
Monetized Value for Flex-1	6,191,361	9,~~548,557~~670,328	4,309,495~~973,430~~
Monetized Value for Flex-2 ($)	1,765,322,893	1,816,115,205	1,722,124,246
Aggregate ($M)	**4,302**	**7,825~~7~~**	**2,756**

The results demonstrate that the aggregated range of cost impacts accrued by the customer range from 2.7$B to 7.8$B over the horizon of forecast uncertainties captured by this analysis. Projects that effectively reduce the customer costs in all benefit categories are most suitable to address the growing needs in the Valley South System.

6.3.3 Benefit-Cost Analysis

The ratio of benefit-cost has been derived across the long-term study horizon. The costs are adopted from Table 6-1 and the monetized benefits are derived using the methodology in Section 3.3. Only relevant benefit categories have been monetized where the energy unserved component is calculated, including EENS, Flex-1, Losses, and Flex-2.

Table 6-4 to Table 6-6 exhibit the benefit-to-cost ratio for the 13 alternatives under three forecasts, wherein alternatives can be ranked against the benefit to cost ratio.

Table 6-4. SCE Effective PV Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$3,882	11.73
F	Valley South to Valley North	$2,156	10.41
I	Valley South to Valley North and Distributed BESS in Valley South	$2,165	9.33
A	Alberhill System Project	$4,282	9.03
B	SDG&E	$4,001	8.84
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2,479	8.58
G	Valley South to Valley North to Vista	$2,470	8.52
E	Mira Loma	$2,601	8.42
J	SDG&E and Centralized BESS in Valley South	$4,041	7.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$2,542	6.93
K	Mira Loma and Centralized BESS in Valley South	$3,132	5.59
C	SCE Orange County	$4,021	5.38
H	Centralized BESS in Valley South	$2,535	4.83

Table 6-5. SCE Spatial Base Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$7,201	21.76
A	Alberhill System Project	$7,788	16.43
B	SDG&E	$7,218	15.93
G	Valley South to Valley North to Vista	$4,617	15.92
E	Mira Loma	$4,766	15.42
F	Valley South to Valley North	$2,618	12.65
I	Valley South to Valley North and Distributed BESS in Valley South	$2,736	12.00
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$4,771	11.81
J	SDG&E and Centralized BESS in Valley South	$7,523	11.43
K	Mira Loma and Centralized BESS in Valley South	$6,604	10.99
C	SCE Orange County	$7,258	9.70
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$6,016	8.59
H	Centralized BESS in Valley South	$6,008	7.08

Table 6-6. PVWatts Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$2,381	7.19
A	Alberhill System Project	$2,740	5.78
B	SDG&E	$2,520	5.56
J	SDG&E and Centralized BESS in Valley South	$2,520	5.26
E	Mira Loma	$1,512	4.89
I	Valley South to Valley North and Distributed BESS in Valley South	$955	4.77
F	Valley South to Valley North	$955	4.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$1,039	4.07
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,036	3.85
K	Mira Loma and Centralized BESS in Valley South	$1,625	3.63
G	Valley South to Valley North to Vista	$1,036	3.57
C	SCE Orange County	$2,533	3.39
H	Centralized BESS in Valley South	$1,032	2.71

As Table 6-4 demonstrates, for the effective PV forecast the Menifee project renders the largest benefit to cost ratio of 11.02. Although the Menifee project has the largest benefit to cost ratio, its cost of $331M is 60% higher than the least expensive project, i.e. Valley South to Valley North with a cost of $207M (Table 6-1). However, the benefit-to-cost ratio of the Valley South to Valley North is 10.41, which is 6% higher. In other words, the additional 40% cost of the Menifee project as compared to the Valley South to Valley North project renders 6% of additional benefit. The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. While it provides an indication of each project's performance, it does not adequately provide a measure to compare alternatives.

The best project among a set of alternative projects is not necessarily the one that maximizes the benefit-to-cost ratio. The benefit-to-cost analysis is a measure consider in the determination to reject or approve a project. But when it comes to the selection among alternatives and the process of reliability improvement projects, an incremental benefit-cost analysis should be conducted. The incremental benefit-to-cost analysis methodology is based on the principle of spending each dollar funding the project that will result in the most benefit, resulting in an optimal budget allocation that identifies the projects that should be funded [10].

To conduct a correct selection among alternative projects with widely disparate benefits an incremental analysis approach to evaluating benefits and costs is necessary [9]. This approach is presented in Section 6.3.4.

6.3.4 Incremental Benefit-Cost Analysis

As described earlier, the incremental analysis starts with ranking alternatives in the ascending order of the present worth of costs. The do-nothing with zero cost is then selected as the baseline, i.e. alternative "0". The next expensive project is then considered, and the incremental benefit-to-cost analysis is then conducted to determine if such a selection should be made or not. The incremental benefit to cost ratio between the baseline and the next expensive alternative is evaluated, which in this case is alternative "F", i.e. Valley South to Valley North. Alternative "F" versus baseline incremental benefit-cost ratio was evaluated using the present worth of monetized benefits versus PVRR costs.

In general, a project is selected if the incremental benefits exceed its incremental cost. This approach can be conducted for non-monetized and monetized benefits. The non-monetized selection is qualitative and subjective as the selection is based on individual indices performance. The monetized analysis is solely based on a single incremental benefit-to-cost ratio. Both non-monetized and monetized incremental cost-benefit analyses are depicted in the following tables. As the selection under non-monetized analysis is subjective, the results are presented for demonstration only.

For monetized incremental cost-benefit analysis, if the incremental ratio is larger than unity the next expensive project "F" is selected. Once a selection is made, the selected alternative replaces the baseline. This selection is demonstrated as "0→F" in Table 6-8. The process continues through the list of alternative projects, which are ranked in ascending cost order until the list is exhausted.

At the next step, the second least expensive project, i.e. "I" is compared to the baseline project "F". Project "I" was not selected as the incremental benefit-to-cost ratio is less than unity, and hence "F" remains as the baseline project. The incremental benefit-cost analysis will continue by iterating between the baseline and the next expensive alternative. The selection will stop once the incremental benefit-cost ratio becomes unfavorable or the list is exhausted. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as environmental impact and risks. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as environmental impact and risks.

For monetized benefits, the criteria to move forward to the next expensive project is considered as a positive (total) aggregated value greater than unity. As one moves along the trajectory of the least cost solutions, the more positive numbers are indicative of improved monetized benefits in each of the categories. If the next expensive alternative presents more favorable returns, and a decision to stop at the previous solution is made, it is representative of benefits that are available but not realized.

The incremental benefit-cost analysis of the monetized benefits is presented in Table 6-8, Table 6-10**,** and Table 6-12 for the Effective PV, Spatial Base, and PVWatts forecasts respectively.

The incremental benefit-cost analysis of non-monetized benefits is presented in Table 6-7, Table 6-9, and Table 6-11 for the Effective PV, Spatial Base, and PVWatts forecasts respectively. The selections were conducted qualitatively and are presented for reference only.

Table 6-7. Non-Monetized Benefits – Incremental Benefit-Cost Analysis – Effective PV Forecast

Category		Alternative selection												
		0 → F	F → I	I→ M	I → G	I → E	I →D	I → L	I → B	B → A	A → H	A → J	A → K	A → C
N-1	LAR	-11.27	-6.50	-0.94	2.80	2.73	1.64	-0.42	-2.32	5.23	-2.20	-1.97	-1.22	1.61
N-1	IP	-0.54	-0.28	0.04	0.12	0.17	0.07	0.02	-0.16	0.97	-0.41	-0.36	-0.22	0.10
N-1	PFD	-1.58	-1.07	-0.16	0.46	0.44	0.27	-0.07	-0.35	0.49	-0.21	-0.19	-0.08	0.08
N-1	Available Flex-1	-5,893.06	-3,339.83	2,223.74	1,439.58	7,537.63	843.39	938.91	317.75	-9,549.32	10,147.65	1,604.86	6,728.74	4,329.79
N-1	Available Flex-2-1	0.00	0.00	0.00	0.00	-5,555.36	-9,860.00	0.00	-4,889.92	-7,682.16	24,377.09	2,889.84	9,482.20	560.54
N-1	Available Flex-2-2	-95.59	-0.02	0.00	0.01	15.28	0.01	0.00	-9.02	-346.00	566.20	130.16	123.05	22.44
N-0	LAR	-36.29	-1.28	-15.50	-14.69	3.84	-10.93	-8.24	-4.59	-4.67	-0.01	-0.01	-0.01	0.36
N-0	IP	-3.70	-0.74	-0.57	-0.38	2.44	-0.58	-0.51	-0.16	-1.55	-0.01	-0.01	0.00	0.12
N-0	PFD	-0.57	-0.10	-0.35	-0.31	0.12	-0.26	-0.20	-0.10	-0.18	-0.01	-0.01	0.00	0.01
Decision to move forward (Y/N)		Y	Y	N	N	N	N	N	Y	Y	N	N	N	N

Table 6-8. Monetized Benefits – Incremental Benefit-Cost Analysis – Effective PV Forecast

Category		Alternative selection												
		0 → F	F → I	F → M	M → G	M → E	E →D	D → L	D → B	B → A	A → H	A → J	A → K	A → C
N-0	EENS	10.356	0.373	3.948	-9.313	-23.358	23.629	0.290	-0.235	1.812	0.003	0.003	0.002	-0.123
N-0	Losses	0.001	0.000	0.000	-0.001	0.018	-0.007	-0.006	0.023	0.055	-0.073	-0.021	-0.045	-0.005
N-1	EENS	0.000	0.000	0.000	-0.009	-0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
N-1	Flexibility-1	0.020	0.009	0.000	0.026	-0.107	0.098	-0.001	-0.008	0.105	-0.044	-0.030	-0.036	-0.016
N-1	Flexibility-2-1	0.000	0.000	0.000	0.000	29.576	34.485	-37.505	1.191	10.992	-33.935	-4.135	-13.246	-0.802
N-1	Flexibility-2-2	0.036	0.000	0.000	0.000	-0.022	0.020	0.000	0.006	0.136	-0.217	-0.051	-0.048	-0.009
Total	Sum of ΔB/ΔC (aggregate)	10.413	0.382	3.947	-9.297	6.087	58.233	-37.216	0.954	13.044	-34.192	-4.213	-13.329	-0.949
Decision to move forward (Y/N)		Y	N	Y	Y	Y	Y	N	Y	Y	N	N	N	N

Table 6-9. Non-Monetized Benefits – Incremental Benefit-Cost Analysis – Spatial Base Forecast

Category		Alternative selection												
		0 → F	F→ I	I → G	I →E	I → D	I → M	M → B	B → A	A→ K	A→ J	A→ L	A→ C	A→ H
N-1	LAR	-33.49	-37.60	12.74	17.76	6.87	-2.55	-33.16	31.64	-5.17	-3.91	4.25	4.87	-1.91
N-1	IP	-0.75	-0.86	0.29	0.28	0.18	-0.03	-1.66	2.46	-0.41	-0.32	0.13	0.23	-0.15
N-1	PFD	-2.16	-0.13	0.04	1.72	0.03	-0.20	-4.41	1.04	0.04	-0.14	0.86	0.22	-0.06
N-1	Available Flex-1	-9,712.04	-12,207.92	4,134.94	11,626.02	2,488.99	-799.25	7,106.92	-1,615.54	1,112.01	-1,621.04	-1,390.76	4,664.64	-419.28
N-1	Available Flex-2-1	0.00	0.00	0.00	-5,369.71	-9,643.82	0.00	-22,563.56	-9,103.32	6,786.12	1,038.97	5,737.98	650.75	3,467.34
N-1	Available Flex-2-2	-113.44	-4.86	1.65	18.85	0.99	0.50	-50.26	-485.96	110.90	55.44	56.05	31.36	94.63
N-0	LAR	-50.38	-18.14	-88.77	-60.88	-96.09	-33.99	-71.33	-41.13	-0.27	-0.19	-0.15	2.84	-0.09
N-0	IP	-4.06	-3.03	-1.72	1.87	-3.25	-1.20	-1.36	-7.01	-0.06	-0.04	-0.03	0.52	-0.02
N-0	PFD	-0.59	-0.22	-1.18	-0.77	-1.43	-0.49	-1.08	-0.62	-0.05	-0.03	-0.03	0.04	-0.02
Decision to move forward (Y/N)		Y	Y	Y	N	N	N	Y	Y	Y	N	N	N	N

Table 6-10. Monetized Benefits – Incremental Benefit-Cost Analysis – Spatial Base Forecast

Category		Alternative selection												
		0 → F	F→ I	I → G	G→E	E → D	D → M	D → B	B → A	A→ K	A→ J	A→ L	A→ C	A→ H
N-0	**EENS**	12.57	5.62	30.35	-23.03	76.11	-14.85	-1.16	13.86	0.10	0.07	0.05	-0.97	0.03
N-0	**Losses**	0.00	0.00	0.00	0.02	-0.01	0.00	0.03	0.08	-0.04	-0.01	-0.02	-0.01	-0.01
N-1	**EENS**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-1	**Flexibility-1**	0.03	0.03	-0.01	-0.17	0.14	0.01	-0.01	0.12	-0.02	-0.01	0.00	-0.02	0.00
N-1	**Flexibility-2-1**	0.00	0.00	0.00	31.04	34.42	-18.45	1.28	12.89	-9.32	-1.47	-7.85	-0.92	-4.74
N-1	**Flexibility-2-2**	0.04	0.00	0.00	-0.03	0.02	0.00	0.01	0.19	-0.04	-0.02	-0.02	-0.01	-0.04
Total	**Sum of ΔB/ΔC (aggregate)**	12.64	5.65	30.34	7.81	110.69	-33.29	0.11	27.07	-9.28	-1.43	-7.82	-1.93	-4.75
Decision to move forward (Y/N)		Y	Y	Y	Y	Y	Y	Y	Y	N	Y	Y	N	N

Table 6-11. Non-Monetized Benefits – Incremental Benefit-Cost Analysis – PVWatts Forecast

Category		Alternative selection												
		0 → I	I → F	I → L	L →M	L→ G	L → E	L→ D	L → H	L → K	L→ B	B → A	A → J	A → C
N-1	LAR	-4.72	0.00	0.00	0.00	0.00	0.51	0.00	-0.52	-0.34	-0.33	0.40	-1.69	0.59
N-1	IP	-0.45	0.00	0.00	0.00	0.00	0.03	0.00	-0.09	-0.06	-0.05	0.17	-0.71	0.06
N-1	PFD	-1.51	0.00	0.00	0.00	0.00	0.12	0.00	-0.10	-0.07	-0.07	0.09	-0.37	0.15
N-1	Available Flex-1	-3,475.85	29.81	0.00	0.00	5.89	9,466.51	2.75	-78.96	2,261.87	-594.68	-11,884.27	43,746.18	3,460.14
N-1	Available Flex-2-1	0.00	0.00	0.00	0.00	0.00	-7,882.61	-12,775.72	0.00	-2,205.50	-5,394.24	-7,225.14	30,345.58	516.40
N-1	Available Flex-2-2	-89.61	0.00	0.00	0.00	0.00	19.50	0.00	141.18	5.46	-8.89	-287.42	1,207.16	18.02
N-0	LAR	-17.11	0.00	-4.37	0.81	0.32	6.52	0.00	0.00	0.00	0.00	-0.01	0.00	0.00
N-0	IP	-2.64	0.00	-1.38	0.44	0.17	2.03	0.00	0.00	0.00	0.00	-0.01	0.00	0.00
N-0	PFD	-0.37	0.00	-0.15	0.07	0.03	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	N	N	N	N	Y	Y	N

Table 6-12. Monetized Benefits – Incremental Benefit-Cost Analysis – PVWatts Forecast

Category		Alternative selection												
		0 → I	I → F	I → L	L → M	L→ G	L → E	E → D	D → H	D → K	D → B	B → A	A → J	A → C
N-0	EENS	4.73	0.00	1.53	-0.19	-0.08	-2.09	5.14	0.00	0.00	0.00	0.00	0.00	0.00
N-0	Losses	0.00	0.00	0.00	0.00	0.00	0.01	-0.01	0.00	0.00	0.02	0.06	-0.28	0.00
N-1	EENS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-1	Flexibility-1	0.01	0.00	0.00	0.00	0.00	-0.04	0.10	-0.02	-0.02	0.00	0.09	-0.35	-0.01
N-1	Flexibility-2-1	0.00	0.00	0.00	0.00	0.00	10.89	34.26	-26.84	-6.44	1.12	10.19	-42.82	-0.73
N-1	Flexibility-2-2	0.03	0.00	0.00	0.00	0.00	-0.01	0.02	-0.13	0.00	0.01	0.11	-0.46	-0.01
Total	Sum of ΔB/ΔC (aggregate)	4.77	0.00	1.53	-0.19	-0.08	8.74	39.52	-26.98	-6.46	1.12	10.39	-43.63	-0.75
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	Y	Y	N	N	Y	Y	N

6.3.5 Levelized Cost Analysis ($/Unit Benefit)

Table 6-13 to Table 6-15 presents the $/Unit Benefit obtained for each alternative under evaluation. The Levelized cost/benefit ratio for each reliability index (LAR through PFD) is calculated for each alternative. For example, in Table 6-13, 0.16 as listed under column A and row N-1 LAR is the ratio of Alberhill project $474 M (Table 6-1) net present cost to present worth of N-1 LAR over study horizon of 2,896 MWh.

A smaller N-1 LAR value implies a more cost-effective solution. Along each row, the ratios are ranked using heat-mapping, with green and red marking the most favorable and the most unfavorable ends of the spectrum. The rightmost three columns, Alternative Rankings, identifies the first three projects per reliability index. The table bottom row, Count of Rank #1, provides the frequency that an alternative ranked first.

Table 6-13. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

Effective PV Forecast

		Alberhill System Project	SDG&E	Valley South to Valley North to Vista	Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	Menifee	Mira Loma	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.16	0.15	0.12	0.17	0.19	0.09	0.14	0.14	0.30	0.14	0.11	0.18	0.09	F	I	M
N-1	IP ↓	3.57	2.94	2.62	3.42	3.70	1.97	2.99	2.95	7.12	3.17	2.50	3.45	1.87	F	I	M
N-1	PFD ↓	1.13	1.05	0.88	1.22	1.31	0.65	1.01	0.96	1.88	1.01	0.79	1.23	0.63	F	I	M
N-1	Flex-1↓	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	F	I	G
N-1	Flex-2-1↓	3.81E-04	4.20E-04			1.31E-03		4.09E-04	7.22E-04	6.86E-04			4.92E-04		A	D	B
N-1	Flex-2-2↓	1.62E-02	2.08E-02	1.47E-02	1.65E+00	3.02E-02	1.17E-02	1.68E-02	1.67E-02	3.25E-02	1.86E-02	1.46E-02	2.44E-02	1.05E-02	F	I	M
N-0	LAR ↓	0.05	0.05	0.03	0.06	0.06	0.03	0.04	0.04	0.09	0.04	0.03	0.06	0.03	F	I	M
N-0	IP ↓	0.56	0.55	0.36	0.62	0.66	0.30	0.39	0.52	0.91	0.43	0.35	0.62	0.27	F	I	M
N-0	PFD ↓	3.24	3.17	2.10	3.58	3.81	1.93	2.28	2.78	5.24	2.50	2.07	3.62	1.76	F	I	M
Count of Rank #1		1	0	0	0	0	0	0	0	0	0	0	0	8			

Table 6-14. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

Spatial Base Forecast

		Alberhill System Project	SDG&E	Valley South to Valley North to Vista	Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	Menifee	Mira Loma	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.05	0.05	0.04	0.09	0.06	0.03	0.05	0.05	0.10	0.09	0.05	0.07	0.03	I	F	G
N-1	IP ↓	2.28	1.75	1.86	3.21	2.32	1.31	2.13	1.99	5.16	3.93	2.27	2.47	1.33	I	F	B
N-1	PFD ↓	0.70	0.65	0.65	1.21	0.89	0.51	0.74	0.69	1.21	1.44	0.83	0.94	0.46	F	I	B
N-1	Flex-1↓	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	F	G	A
N-1	Flex-2-1↓	3.66E-04	4.10E-04			1.38E-03		3.33E-04	3.11E-04	6.69E-04			5.95E-04		E	D	A
N-1	Flex-2-2↓	1.31E-02	1.74E-02	1.23E-02	1.10E+00	2.72E-02	9.67E-03	1.41E-02	1.32E-02	2.71E-02	2.98E-02	1.72E-02	2.53E-02	8.81E-03	F	I	G
N-0	LAR ↓	0.02	0.02	0.02	0.04	0.03	0.02	0.02	0.01	0.04	0.03	0.02	0.03	0.02	E	D	G
N-0	IP ↓	0.36	0.38	0.29	0.63	0.45	0.25	0.27	0.25	0.63	0.52	0.36	0.49	0.25	F	E	I
N-0	PFD ↓	1.70	1.71	1.45	2.98	2.11	1.80	1.21	1.13	2.80	2.46	1.90	2.31	1.70	E	D	G
Count of Rank #1		0	0	0	0	0	2	0	3	0	0	0	0	4			

Table 6-15. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

PVWatts Forecast

		Alberhill System Project	SDG&E	Valley South to Valley North to Vista	Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	Menifee	Mira Loma	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**	**#1**	**#2**	**#3**
N-1	**LAR ↓**	0.47	0.45	0.31~~0.33~~	0.38	0.44	0.21	0.35	0.34~~0.61~~	0.89	0.27	0.29	0.47	0.22	I	F	L
N-1	**IP ↓**	4.91	4.52	3.25~~3.45~~	3.80	4.47	2.24	3.70	3.51~~12.58~~	9.37	2.85	3.01	4.78	2.31	I	F	L
N-1	**PFD ↓**	1.51	1.43	0.96~~1.02~~	1.21	1.42	0.66	1.09	1.04~~1.15~~	2.75	0.84	0.89	1.52	0.68	I	F	L
N-1	**Flex-1↓**	0.0005	0.0006	0.0004	0.0006	0.0014	0.0003	0.0005	0.0017	0.0065	0.0004	0.0004	0.0006	0.0003	I	F	L
N-1	**Flex-2-1↓**	3.89E-04	4.24E-04			1.05E-03		3.41E-04	7.26E-04	6.94E-04			4.48E-04		D	A	B
N-1	**Flex-2-2↓**	1.84E-02	2.30E-02	1.72E-02	2.87E+00	2.66E-02	1.12E-02	1.85E-02	1.83E-02	3.60E-02	1.42E-02	1.50E-02	2.43E-02	1.16E-02	I	F	L
N-0	**LAR ↓**	0.13	0.12	0.08	0.10	0.12	0.06	0.09	0.10	0.20	0.07	0.07	0.13	0.06	I	F	L
N-0	**IP ↓**	0.79	0.75	0.49~~0.52~~	0.63	0.74	0.38	0.55	0.55~~0.63~~	1.24	0.42	0.45	0.79	0.39	I	F	L
N-0	**PFD ↓**	5.78	5.53	3.59~~3.82~~	4.65	5.46	2.71	4.04	4.04~~4.14~~	9.12	3.11	3.32	5.84	2.80	I	F	L
Count of Rank #1		0	0	0	0	0	8	1	0	0	0	0	0	0			

6.4 Risk Analysis

The risk analysis performed within this assessment is deterministic. As stated earlier, three forecast sensitivities were considered: Effective PV, Spatial Base, and PVWatts forecasts. The Effective PV forecast closely matches the expected load growth in the Valley South region. The Spatial Base and PVWatts forecasts are located above and below the Effective PV and thus were used as upper and lower bounds of uncertainty that characterize variability in the adoption of DER, impacts of electrification, and overall impacts of load reducing technologies.

Table 6-16 presents a comparison of the benefit-cost ratios as they vary with different forecasts.

Table 6-16. Deterministic Risk Assessment

Project	Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Alberhill System Project	9.03	16.43	5.78
SDG&E	8.84	15.~~94~~93	5.56
Valley South to Valley North to Vista	8.52	15.92	3.57~~35~~
Centralized BESS in Valley South	4.83	7.08~~9~~	2.71
Mira Loma and Centralized BESS in Valley South	5.59	10.99	3.63
Valley South to Valley North and Distributed BESS in Valley South	9.33	12.00~~1~~	4.77
Menifee	11. 73~~02~~	21.76	7.19
Mira Loma	8.42	15.42	4.89
SCE Orange County	5.38	9.70~~1~~	3.39
Valley South to Valley North and Centralized BESS in Valley South and Valley North	6.93	8.59~~60~~	4.07~~8~~
Valley South to Valley North to Vista and Centralized BESS in Valley South	8. 58~~54~~	11.81	3.85
SDG&E and Centralized BESS in Valley South	7.61	11.43	5.26
Valley South to Valley North	10.41	12.65	4.61

6.5 Summary of Findings

The evaluation of findings from the variety of benefit-cost analyses are presented below:

1. Without a project in service to address the needs in the Valley South System, the aggregate cost impacts accrued by the customer range from 2.7$B to 7.8$B over the horizon of forecast uncertainties captured by this analysis.
2. The benefit-cost analysis demonstrates Menifee as the project with the highest B-C ratio in Effective PV, Spatial Base, and PVWatts forecast. This is followed by the Alberhill System project and San Diego Gas & Electric. In the case of Valley South to Valley North alternatives, the project's low cost overrides the performance benefits and drive the ratios higher. The Menifee alternative has an advantage of lower cost while providing superior performance to Valley South to Valley North alternatives in select (Flex-2) categories. However, the benefits are realized only in the short

term horizon, with limited long-term benefits. A quick review of the overall benefits in Section 6.3.3 and raw reliability performance in Section 5.3.3, 5.3.5 and 5.3.6 further justifies this claim. The benefits accrued by ASP were found to be substantial over the horizon maintaining its rank across all three forecasts.

3. An evaluation of the $/Unit Benefit demonstrates that non-wire alternatives are favorable only under lower levels of forecasted growth. This is observable from the ranking of projects presented in Section 6.3.5.
4. Wire-based solutions demonstrate higher $/Unit benefit performance under the Effective PV and Spatial Base forecasts of load growth.
5. The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected. Using the Effective PV forecast as an example, if a decision is made to stop at Menifee due to superior performance in comparison to Valley South to Valley North to Vista and Baseline system, several projects are found to provide additional benefits to the system. This trend continues till a decision is made to stop at Alberhill System Project.
6. An overall assessment of the top-ranking alternatives with consideration of risks, demonstrate the superiority of ASP to meet all the short term and long-term project objectives in the Valley South System.

7 CONCLUSIONS

SCE retained Quanta Technology to supplement the existing record in the CPUC proceedings for SCE's ASP with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this analysis is to amend the ASP business case (including BCA) and alternative study using rigorous and data-driven methods.

A comprehensive framework was developed in coordination with SCE to evaluate and rank the performance of alternatives. This evaluation is complemented by the development of load forecasts for the Valley South System planning area. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for alternatives used power flow studies in coordination with quantitative analysis to forecast the impacts of alternatives under evaluation, including the ASP. The forecasted impacts are translated into key reliability metrics, representative of project performance over a 30-year horizon. Detailed analysis of alternatives used the benefit-cost and risk analysis framework to quantify the value of monetary benefits observed over the project horizon.

A total of 13 alternatives, including the ASP, were evaluated within this framework to validate performance and contribution towards satisfying project objectives. These alternatives were categorized into Minimal Investment, Conventional, Non-Wire, and Hybrid (Conventional plus Non-Wire) solutions.

The key findings of this study are summarized as follows:

- Consistent with the industry-accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely conventional and spatial forecasts. (The load forecasting methodologies and findings are documented in detail within Section 2 of this report.)
  - The two forecasts have been developed consistent with the load-growth trend currently observed within the region, and CEC's IEPR projections for load-reducing technologies.
  - Sensitivity analysis was performed to address the uncertainties of load-reducing technologies and California's electrification goals.
  - Across the three forecasts, the reliability need year was identified as 2022, except for one sensitivity that identified 2021 as the need year.
  - The Effective PV spatial load forecast is found to be the most consistent with trends in the Valley South needs area. This forecast demonstrates a range of load from 1,083 MVA to 1,377 MVA over 2019–2048.
- Several reliability metrics were used to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that the ASP provides the highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resilience, and operational flexibility needs in the Valley South System.

Considering the aggregated benefits under normal and emergency[12] conditions, the ASP results in 76 gigawatt-hours (GWh) of cumulative reduced unserved energy, and $4.3 billion in cost savings to the customers. The alternatives demonstrating the highest benefits following the ASP are SDG&E, SCE Orange County, and SDG&E with Centralized BESS in Valley South.

- The BCA framework was implemented to evaluate and compare individual alternatives' performance.
  - NWAs remained cost-effective only under reduced load forecast levels (e.g., reduced trend and low sensitivities of the conventional forecasts). In the other forecasts, NWAs accrue significant additional costs over time due to the incremental storage sizing necessary to address the load growth in the Valley South System.
  - Conventional and Hybrid alternatives can better satisfy project objectives and long-term reliability challenges in the system.
  - Menifee, ASP, SDG&E, and Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Menifee and Valley South to Valley North have lower costs relative to the ASP while providing sizably lower benefits than the ASP.
- The benefit-to-cost ratio is one measure to consider in determining if any project should be implemented. However, when it comes to the selection among alternatives, an incremental BCA should be conducted. Incremental BCA methodology determines whether additional incremental cost is economically justifiable on the basis that the additional benefits realized exceeds the incremental cost.
- The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected.
- Risk analysis associated with forecast uncertainties demonstrate that:
  - The costs associated with the incremental size of the NWAs (to keep pace with peak load values) are substantial and result in reduced benefit-cost ratios.
  - The benefits attributed to operational flexibility from NWAs are negligible.
- The results of the reliability, benefit-cost, and risk analyses indicated that the ASP meets the project objectives over the 10-year horizon and ranks the most favorable among the considered alternatives over the 30-year horizon.

Findings and results reported in this document are based on publicly available information along with the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

[12] N-0, N-1 and operational flexibility.

8 REFERENCES

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9 APPENDIX: N-2 PROBABILITIES

The N-2 probabilities associated with circuits that share a common tower structures are presented in this table.

	Auld-Moraga #2	Auld-Sun City	Fogarty-Ivyglen	Moraga-Pechanga	Pauba-Triton	Valley-Auld #1	Valley-Auld #2	Valley-Elsinore-Fogarty	Valley-Newcomb	Valley-Newcomb-Skylark	Valley-Sun City	Valley-Auld-Triton	Valley-Ivyglen
Auld-Moraga #2				0.0088	0.0194							0.02696	
Auld-Sun City										0.0304			
Fogarty-Ivyglen													0.0032
Moraga-Pechanga	0.0088												
Pauba-Pechanga													
Pauba-Triton	0.01944											0.002	
Valley-Auld #1							0.0698						
Valley-Auld #2						0.0698						0.016	
Valley-Elsinore-Fogarty									0.024				
Valley-Newcomb								0.024					
Valley-Newcomb-Skylark		0.0304									0.0309		
Valley-Sun City										0.03096			
Valley-Auld-Triton	0.02696				0.002		0.016						
Valley-Ivyglen			0.0032										